Allan J. Thompson, Esq.
21 "C" Orinda Way, #314
Orinda, CA 94563
925-258-9962
925-258-9963 (FAX)

June 28, 2004

CALIFORNIA ENERGY COMMISSION
DOCKET UNIT, MS-4
1516 Ninth Street
Sacramento, CA 95814-5512

Re: Docket No. 04-SPPE-01

Enclosed for filing in the above-captioned matter are an original and 12 (twelve) copies of the **Response to CURE Data Requests Set 1**.

Sincerely,

Allan J. Thompson, Esq.
One of Counsel for
City of Riverside Public Utilities

AJT:dmg
Enclosures

BEFORE THE
ENERGY RESOURCES CONSERVATION
AND DEVELOPMENT COMMISSION
OF THE STATE OF CALIFORNIA

APPLICATION FOR CERTIFICATION FOR THE RIVERSIDE ENERGY RESOURCE CENTER PROJECT	))))	**Docket No. 04-SPPE-01**

PROOF OF SERVICE

I, Diane M. Gilcrest, declare that on June 28, 2004 I deposited copies of the attached **Response to CURE Data Requests Set 1** in the United States mail in Walnut Creek, CA with first class postage thereon fully prepaid and addressed to the following:

DOCKET UNIT

CALIFORNIA ENERGY COMMISSION
Attn: Docket No. 04-SPPE-01
DOCKET UNIT, MS-4
1516 Ninth Street
Sacramento, CA 95814-5512

APPLICANT

Stephen H. Badgett
Utilities Assistant Director
Riverside Public Utilities
3900 Main Street
Riverside, CA 92522

Robert B. Gill
Principal Electrical Engineer
Riverside Public Utilities
3900 Main Street
Riverside, CA 92522

Dave Tateosian, P.E.
Project Manager
Power Engineers, Inc.
P.O. Box 2037
Martinez, CA 94553

Kevin L. Lincoln
Environmental Project Manager
Power Engineers, Inc.
3940 Glenbrook Drive, Box 1066
Hailey, Idaho 83333

ATTORNEY FOR APPLICANT

Allan J. Thompson, Esq.
21 "C" Orinda Way, #314
Orinda, CA 94563

INTERVENORS

California Unions for Reliable Energy
Marc D. Joseph
Adams, Broadwell, Joseph & Cardozo
651 Gateway Boulevard, Suite 900
South San Francisco, CA 94080

John Yee and Ken Coats
South Coast Air Quality
Management District
21865 E. Copley Drive
Diamond Bar, CA 91765-4182

INTERESTED AGENCIES

Kate Kramer
CA Department of Fish and Game
4775 Bird Farm Road
Chino Hills, CA 91709

Milasol Gaslan
Santa Ana Regional Water
Quality Control Board
3737 Main Street, Suite 500
Riverside, CA 92501

Guenther Moskat, Chief
Planning and Environmental
Analysis Section
Department of Toxic and Substance
Control
1001 "I" Street, 22nd Floor
P. O. Box 806
Sacramento, CA 95812-0806

Mr. R. Austin Wiswell, Chief
Division of Aeronautics
Department of Transportation
1120 N Street, MS 40
Sacramento, CA 94273-0001

I declare under penalty of perjury that the foregoing is true and correct.

Diane M. Gilcrest

Diane M. Gilcrest

RIVERSIDE ENERGY RESOURCE CENTER
SMALL POWER PLANT EXEMPTION
RESPONSE TO CURE DATA REQUESTS SET 1
04-SPPE-01

GENERAL

1. Units 3 and 4 and Substation Expansion

Background

During the May 25, 2004 Site Visit and Informational Hearing on the Project, the Applicant indicated that it was "making provisions" for two more turbines to be added to the RERC Project between 2011 to 2015 ("Units 3 and 4"). The Application makes no mention of this planned expansion in the Application, even though it is a "reasonably foreseeable" future phase of the Project.

The Application also states that the Project will include expansion of a number of substations and construction of a gas pipeline. The Application does not include these activities in its impact analysis.

Data Requests

1.a Please provide a full visual and written description of the proposed Units 3 and 4, including, but not limited to, their size, configuration, generating capacity, and location in relation to Units 1 and 2.

Response: There are no specific plans or commitment to Units 3 and 4 at this time. Since the site was larger than needed for two simple cycle units, it was only prudent to layout the site to allow for future growth if needed. To that end, we considered what a comfortable maximum build out could be and developed a site layout illustrating four LM6000s in combined cycle as a proxy. . This was only done so as not to preclude future expansion in the event it is ever considered. That General Arrangement, single line drawing, and the corresponding "bird's eye view" visual simulation are also included as a part of this response.

1.b Please describe all "provisions" you plan to make for two additional turbines at the site.

Response: We included the following provisions in the plant design:

- We provided a Control Room that could accommodate additional control consoles in the future.

- We sized the water tanks with spare capacity.
- We are including tees in the piping for critical systems to minimize the difficulty of future tie-ins, e.g., tees in the natural gas line as it proceeds south to Units 1 and 2.

1.c Please disclose whether Units 3 and 4 will be combined-cycle or simple cycle units.

Response: This is not known at this time. As stated earlier, we arbitrarily laid out the site for four LM6000s. What additional generation gets built, if any, and whether they are simple or combined cycle, will depend on many factors including:

- Load growth
- Anticipated resource needs (how much, base load, intermediate, or peaking)
- The electricity market structure
- Availability/reliability/cost of external supplies
- Available engine technologies
- Permitting
- City approvals

Units 3 and 4 may ultimately be LM6000s or some later technology engine. However, any further engine installation occurs, it is several years off in the future and the configuration and technology are unknown.

1.d Please perform a complete impact analysis of all phases and aspects of the Project, including:

1.d.i The construction and operation of Units 3 and 4;

Response: It is not possible to do so at this time because the specific design for Units 3 and 4 is not known and will not be known until a decision is made to pursue them.

1.d.ii The proposed creation and/or expansion of all substations discussed in the SPPE application, including the RERC substation, the Mt. View substation, and the Riverside substation, and;

Response: As previously stated in our response to CURE's questions that were included in the response to the Staff's Data Requests, the only changes involve replacement of existing relays and circuit breakers and there will be no change to the substation footprints.

1.d.iii The construction of the approximately 140-foot natural gas line that will "connect the existing Sempra transmission pipeline to the on-site meter station." (Described on p. 7 of the Application)

Response: The plant will interconnect to Sempra's gas transmission system which runs along the north edge of the site. The "transmission line" that will be built is largely all on the site property and extends from the existing Sempra transmission line to the meter station on the site.

1.e Please provide any and all documents related to the expansion of the Project beyond Units 1 and 2.

Response: We are providing the General Arrangement, single line drawing, and the corresponding "bird's eye view" visual simulation that were developed as a part of our response to Data Request 1.a.

1.f Please provide any and all documents related to Units 3 and 4.

Response: We are providing the following documents:

- POWER Engineers letter 34-220 dated July 1, 2003, Plant Configuration Study – Initial Results – Addendum 1
- M1-4 Plant Arrangement Combined Cycle
- E1-4 Key One Line Diagram Ultimate Combined Cycle
- E1-7-3 Substation General Arrangement Ultimate Combined Cycle
- Visual Simulation Ultimate Combined Cycle
- Meeting minutes that discussed plant configuration

We were unable to locate the original 34-220 report, however as stated in Addendum 1, it envelopes the original report.

2. Cumulative Impact Analysis

Background

While a single project may not result in a condition that results in unacceptable air quality impacts, the cumulative exposure to the RERC Project and other projects in Riverside County may result in cumulatively significant health impacts.

Data Requests

2.a Please perform a cumulative impact analysis and include air quality impacts from the following sources:

2.a.i The adjacent City of Riverside Wastewater Treatment Plant ("WWTP");

2.a.ii The adjacent City of Riverside WWTP cogeneration plant;

2.a.iii Any and all other sources that have received permits authorizing construction, but are not yet in operation; and

2.a.iv Any and all sources which have commenced operation, subsequent to the data used to establish background air quality levels, i.e. after the year 2002.

Response: The applicant has filed an objection to this request relative to 2.a.i and 2.a.ii. The wastewater treatment plant has been in operation for all of the 10 years for which ambient air quality trends were extracted in support of the project's air quality impact analysis. The cogeneration engines were installed no later than 2001. The impacts from the cogeneration engines are included in air quality trends recorded for the years 2001, 2002 and 2003.

See response to CEC Data Request 19 for additional information relative to requests 2.a.iii and 2.a.iv. CEC and AQMD conducted a search of sources within a 6-mile radius of the project that have been issued a permit to construct, but have not been issued a permit to operate. The agencies also researched outstanding applications for permits to construct, but for which the permits have not been issued. The search resulted in identifying only applications for "like in kind" equipment changes, with no applications outstanding or permits issued for modifications that would result in potential emission increases that would not conceivably be included in the year 2003 baseline emissions that were used in the ambient air quality impact analyses of the proposed project. CEC independently researched filings of EIRs for projects within the 6-mile radius and found no record of proposed projects that would result in emission increases. Correspondence from CEC and SCAQMD regarding the investigation is included in Appendix 6.1-G.

3. Potential Operating Scenario

Background

A full understanding of the RERC Project's planned operating scenario is essential to understanding the RERC Project's impacts. As CEC staff noted in its first set of data requests and at the May 25, 2004 Informational Hearing and Workshop, the Application does not provide a consistent operating scenario for the RERC Project. During the May 25, 2004 data request workshop, in response to staff's first data request, the Applicant stated that the design basis hours of operation will be 1,330 hours per turbine per year.

At the May 25 Informational Hearing and Workshop, the Applicant noted that due to expiring contracts and population increases, the City's energy demand and supply scenario is expected to change significantly over the next decade. For purposes of an accurate and full impact assessment under CEQA that includes an analysis of "reasonably foreseeable" phases of the project, a full understanding of how the operation of the RERC Project will fit into this demand/supply scenario is critical.

Data Requests

3.a Please verify that the Applicant is willing to accept a Condition of Certification ("COC") that limits operation of the plant to 1330 hours per year per turbine.

Response: The application is for an SPPE and is intended to result in SCAQMD issuing a permit to construct and a permit to operate the facility. SCAQMD permitting policy and regulations dictate that enforceable conditions be included in the permit to ensure compliance with new source review regulations. The applicant is willing to accept permit conditions as specified and enforced by SCAQMD. Because the two turbines are identical in rating and emissions profiles, and given the new source review provisions that would dictate the limit, it is appropriate for SCAQMD to draft permit conditions based upon total facility operations, rather than individual turbine operations. The applicant envisions that SCAQMD will issue a permit condition limiting total facility-wide operations to 2,660 hours per year, or an equivalent fuel throughput limit.

3.b Please provide all analyses or documents that consider operating the RERC Project for more than 1330 hours per year per turbine.

Response: All analyses reflect operations of 1,330 hours per year, per turbine. No additional relevant data are available.

When the project was originally conceived as a single turbine, the maximum anticipated operating hours were considered to be 2,000 hours per year. Subsequently alternative approaches were explored prior to the decision to go with two turbines to capture the benefit of reduced costs in the marketplace and the efficiency of building two units at the same time, the operating hours were re-evaluated and then modified from 2,000 for a single turbine to 2,660 for two turbines. The value of 1,330 hours was derived based on air permitting requirements and was satisfactory to meet anticipated energy demands. The modeling for two units indicates the total operating hours, for the two turbines, to be between 1179 and 1472 hours per year. The additional hours will provide operational flexibility in order to cope with unforeseen events.

3.c Please provide all resource plans for the City of Riverside, documenting demand (peak, average, total energy served, etc.) and all sources of supply (peak capacity, reserves, total energy, etc.). Resource plans should be provided for every year for which plans have been prepared.

Response: Please see attachment.

3.c.i Please disclose the RERC Project's anticipated operating scenario, including number of hours per year, during each year from 2005 through 2035.

Response: The RERC units will operate during the summer peaking season of May through October, typically a few hours in the afternoon when air conditioning loads are at their maximum. Operation outside those months will be limited to required testing or emergency situations. The current Riverside Resource plan includes the fiscal years 2005 through 2013, data for years beyond 2013 have yet to be developed. The annual combined operating hours for the two turbines varies from 1179 to 1472 hours for the years 2006 through 2013.

3.c.ii Please provide all documents that support your answer.

Response: Please see attachment.

3.d Please provide the schedule for all energy supply contracts that will expire beginning in 2006, and the capacity and energy that these contracts provide. Please provide documentation to support your responses.

Response: Without waiving its prior objections regarding the relevancy of the information requested, Riverside provides the following response. Due to security concerns, Applicant is providing a summary of the contracts per direction from the CEC Staff:

Riverside has not compiled in the normal course of business a "schedule" related to the termination or expiration of its supply contracts. Nevertheless, the following information is provided in connection with Riverside's supply resources that are expected to terminate or expire during or after 2006.

Certification regarding preparation of response: The foregoing response was prepared by Counsel with information provided by Gary Nolff and Dan McCann.

Energy associated with each contract listed below is variable depending on the equipment condition, ambient weather conditions and the City's demand requirement.

<u>Intermountain Power Project</u>
Comments: Subject to ambient weather conditions, Riverside's current capacity entitlement is approximately 137 MW.
Expires: 2027

Deseret Generation & Transmission Cooperative
Comments: 52 MW
Expires: 2009

Hoover Power Plant
Comments: 30 MW
Expires: 2017

San Onofre Nuclear Generating Station
Comments: Subject to ambient weather conditions, Riverside's current capacity entitlement is approximately 38.5 MW.
Expires: Ownership

Palo Verde Nuclear Generating Station
Comments: Subject to ambient weather conditions, Riverside's current capacity entitlement is approximately 12 MW.
Expires: 2027

Mid Valley
Comments: 2.5 MW
Expires 2007

Milliken
Comments: 2.5 MW
Expires: 2007

Badlands
Comments: 1 MW
Expires: 2007

Wintec
Comments: 1.32 MW
Expires: 2017

Bonneville Power Administration Sale/Exchange
Comments: 23 MW
Expires: 2010

Bonneville Power Administration Diversity Exchange
Comments: 60 MW
Expires: 2115

California Department of Water Resources 2004 WSPP Purchase
Comments: 50 MW
Expires: 2007

California Department of Water Resources 2004 WSPP Purchase
Comments: 53 MW
Expires: 2010

3.e Please provide any and all documents that relate to the RERC Project's potential operating scenario.

Response:

4. Number of Workers

Background

The Application states that "no more than five" people will be working at the facility at any given time (Application, p. 238), but it does not provide an explanation of how the Applicant arrived at that number.

Data Requests

4.a Please disclose how many workers will be hired to operate the plant.

Response: There will be two union (IBEW) Generation Technicians hired to operate the Riverside Energy Resource Center. One existing management position is also expected to be stationed at the plant.

4.b Please provide a job description for each of the workers who will be hired to operate the plant, including whether such position is a fulltime or part-time position.

Response: Attached is the job description for the two full time Generation Technicians described above.

4.c Please explain whether the plant will be staffed on a 24/7 basis.

Response: The plant will not be staffed on a 24/7 basis.

AIR QUALITY

5. WATER INJECTION VS. DRY LOW -NOX BURNERS

Background

The Applicant proposes to use water injection into the combustion turbine generators to control NOx emissions to 25 ppmv at 15 percent oxygen ("O_2") before further reduction through the selective catalytic reduction ("SCR) system. (Application, p. 71.) Because NOx formation during combustion increases exponentially with flame temperature, by adding water or steam, the flame temperature decreases and NOx emissions fall as well. A drawback to water injection is that a reduction in flame temperature also tends to increase CO emissions.

Since the mid-1980s, gas turbine manufacturers have been offering dry low-NOx ("DLN") combustors, which produce low NOx emissions without the addition of water or steam and without the drawback of higher CO emissions. A combination of DLN combustors with SCR plus a CO catalyst are generally considered BACT for natural gas-fired gas turbines. Such DLN combustors are available and have been used in simple-cycle facilities. For example, the CalPeak Power Border facility in San Diego; the CalPeak Power Panoche facility in Firebaugh; the GWF Energy Tracy Peaker Power Plant in Tracy, CA; and the PG&E Dispersed Generating Company Chula Vista facility in Chula Vista, CA; all operate simple-cycle natural gas-fired turbines with DLN combustors, SCR, and a CO oxidation catalyst. In addition, General Electric has recently introduced a DLN combustor for the LM6000 gas turbine (proposed for the RERC Project), available in early 2005.[1] This GE DLN combustor has a demonstrated simple-cycle efficiency greater than 40%, which at full power does not exceed NOx emissions of 15 ppm.

The South Coast Air Quality Management District ("SCAQMD") requires the application of Best Available Control Technology ("BACT") for any new or modified emissions unit resulting in an emissions increase of any non-attainment air contaminant, any ozone-depleting compound, or ammonia. The SCAQMD's BACT Guidelines[2] define BACT as the most stringent emission limitation or control technique which:

(1) has been achieved in practice for such category or class of source; or

(2) is contained in any state implementation plan (SIP) approved by the United States Environmental Protection Agency (EPA) for such category or class of source. A specific limitation or control technique shall not apply if the owner or operator of the proposed source demonstrates to the satisfaction of the Executive Officer or designee that such limitation or control technique is not presently achievable; or

(3) is any other emission limitation or control technique, found by the Executive Officer or designee to be technologically feasible for such class or category of sources or for a specific source, and cost-effective as compared to measures as listed in the Air Quality Management Plan (AQMP) or rules adopted by the District Governing Board.

The Applicant did not conduct a BACT analysis for the RERC Project, instead contending with no support at all that "[o]verall, the proposed emission rates reflect recently permitted simple-cycle projects in California, and are believed to reflect the lowest achievable emission rates for simple cycle turbines rated above three megawatts."

Data Requests

5.a Please provide all reasons that justify the use of water injection in lieu of dry low-NOx combustors to control NOx emissions from the RERC Project gas turbines.

Response: Water injected engines were selected for the RERC for several reasons:

- Water injected engines are not as technologically challenging as compared to dry low NOx engines. This provides benefits with regard to quick startups, ramp rates, and combustion stability.
- Dry low NOx engines typically cost more and have a lower output than water injected engines.
- Both dry low NOx and water injected engines both have the same emissions output guarantees. Both require SCRs in the California marketplace.
- The use of dry low NOx engines has sometime occurred independent of any emissions reason. The driving force in these cases has been capitalizing on the dry low NOx engines lower output to stay under the CEC 50 MW licensing threshold. The CalPeak plants are a case in point as the water injected FT8 TwinPak exceeds 50 MW under the majority of conditions.
- Water injected engines are much more widely used in California than dry low NOx engines (for the reasons stated above)

For the above reasons, the Applicant concluded that a water injected engine was in the City's best interests.

5.b Please provide all documents supporting your answer to Data Request 5.a.

Response: Enclosed is POWER Engineers report 34-182 dated May 19, 2003, RPU Engine Selection Evaluation.

6. AMMONIA SLIP

Background

Ammonia ("NH_3") is a precursor for secondary particulate matter formation. The excess residual ammonia, the so-called ammonia slip, downstream of the SCR system reacts with sulfuric acid mist as well as nitrogen dioxide and water vapor in the stack gases and downwind in the atmosphere to form ammonium sulfate, ammonium bisulfate, and ammonium nitrate.

The Application states that "NH_3 emissions resulting from the use of

SCR will be limited to 5 ppmv, based upon SCAQMD BACT standards." (Application, p. 71.) However, lower ammonia slip levels can be readily and inexpensively achieved using a standard SCR system designed to meet a lower slip and, considering the non-attainment status of the South Coast Air Basin ("SoCAB") for PM10, should be required for the RERC Project.

There are a number of facilities that are successfully operating with both low NOx and lower ammonia slip levels than proposed for the RERC Project. Massachusetts, Connecticut, Rhode Island, and other states have established 2 ppmv ammonia slip BACT limits for new power plants. For example, Rhode Island requires all power plant permit applicants to justify why they cannot achieve a 2 ppm ammonia slip for SCR as part of their BACT analysis. Several projects in Massachusetts and Connecticut have been issued Prevention of Significant Deterioration ("PSD") permits specifying a NO_x limit of 2 ppmv achieved with a 2 ppmv ammonia slip, demonstrated using an ammonia CEMs and both averaged over 1 hour. Two of these facilities are currently operating with NH_3 slip levels less than 1 ppmv, demonstrated by CEMS. All of the major SCR vendors have long been offering performance guarantees of 2 ppmv Ammonia slip, averaged over one hour, to compete in the New England market.

Further, several facilities in California similar to the RERC Project are now successfully operating at NOx levels of less than 2.5 ppmv and ammonia slip levels less than or equal to 1.5 ppmv at 15 percent O_2, viz. the Calpine Lambie, Creed, and Goose Haven Energy Centers in Suisun City, CA; all three simple-cycle peaker facilities with GE LM6000 PC Sprint gas turbines with water injection, SCR systems, and CO oxidation catalysts. (CARB 03/04[4], Appx. B.)

Data Requests

6.a Does the Applicant acknowledge that limits of 2 ppmv for ammonia and 2.5 ppmv for NOx at 15 percent O_2 have been achieved in practice in gas-fired simple-cycle power plants and are feasible for the RERC Project?

Response: Applicant acknowledges that 2.5 ppmv NO_x is achieved in practice, but does not concur with CURE's suggestion that 2.0 ppmv NH_3 is achieved in practice, or is feasible for simple-cycle gas turbines.

In the examples of simple-cycle permitting projects cited by CURE, only one permit has been issued for a NH_3 rate of 2 ppmv. The project, Lowell Power, has yet to be constructed and operated, so its ability to meet the stated limit has not been demonstrated. It is also unclear what types of exemptions from the 1-hour limit will be included in the final operating permit. All other issued construction permits that are cited in the reference document include NH_3 limits of 5 ppmv to 25 ppmv, with averaging periods of up to 24-hours.

6.b If the answer to the above data request is no, please provide documentation to demonstrate why an ammonia slip limit of 2 ppmv at 15 percent O_2 is not technologically feasible for the RERC Project. In this case, please explain why the emissions measured at the Calpine Lambie, Creed, and Goose Haven Energy Centers in Suisun City, CA, do not individually establish BACT or collectively establish BACT for ammonia slip for the RERC Project. Please provide supporting data for any of these facilities that you believe do not demonstrate a lower ammonia slip limit than 5 ppmv at 15 percent O_2.

Response: BACT and emission guarantees reflect performance that can continue to be achieved as the SCR ages and performance that can be achieved under a variety of operating conditions. They also reflect performance that can be achieved at the end of a reasonable useful life of the system, rather than only immediately following system installation. Demonstrations of achieved in practice emission rates are typically made based upon an exhaustive body of data reflecting at least six months of operating data for full time operations. If peaking operations were used to make an achieved in practice determination, an equivalent 4,380 hours of actual operating data should be considered. Performance under these circumstances has not been demonstrated through the test results cited by CURE.

The emissions data used by CURE is extracted from CARB's March 2004 draft report of gas-fired power plant NOx emission controls. CARB advises the reader that the report is not intended to establish BACT levels or to validate any levels purported to be achieved at the cited facilities. The field emissions that are contained in the report reflect one-time tests that were conducted immediately after the gas turbines and emission control systems were commissioned and do not identify degradation that will occur during the useful life of the SCR system. The test data also do not reflect variability that can exist due to changes in load, impurities in aqueous ammonia batches, stratification that can occur due to clogged injectors or contaminated catalyst or other conditions that can occur during the operating life of the SCR system.

While the NH_3 results cited in the CARB reference materials appear to be favorable, the reader must also note that they are anything but consistent across the sampling of LM6000 projects. Cited NH_3 results ranged from 0.76 ppmv to 24.49 ppmv, for the projects listed in the report. The reader must also consider the level to which NO_x emissions are in compliance with a 2.5 ppmv limit, while simultaneously demonstrating NH_3 emissions below 2 ppmv. The Lambie project test results for NOx are at 98% of the 2.5 ppmv limit, while the Goose Haven project results are at 96% of the 2.5 ppmv limit for NO_x. It is not likely that the measured NH_3 levels can be maintained as the SCR system ages without jeopardizing compliance with the 2.5 ppmv NO_x limit.

6.c There are two methods that can be used to meet a lower slip limit, increasing the volume of catalyst and using an oxidizing layer downstream of the SCR catalyst to convert ammonia to N_2 and water. The Application did not evaluate either of these two methods of meeting a lower ammonia slip limit than 5 ppm.

6.c.i A standard SCR system can be designed to include an oxidizing layer downstream of the SCR catalyst. The oxidizing layer would oxidize ammonia to nitrogen gas and water. Two major catalyst vendors are commercially offering this system for gas turbines, Cormetech and Engelhard. Near-zero slip levels can be readily and inexpensively achieved using this system. Please specifically evaluate the use of an oxidizing layer to meet an ammonia slip limit of 2 ppmv at the RERC Project.

Response: While the enhanced NH_3 control through additional catalyst layers may be viable technology for frame technology, combined-cycle gas turbines, they can be problematic for simple-cycle gas turbines and for aero-derivative technology turbines such as the LM6000 units that are proposed for the RERC project. Aero-derivative gas turbines are more restricted by backpressure considerations than larger turbines that are based on frame technology. It is estimated that for each 1" WC of increased backpressure, turbine fuel efficiency decreases by approximately 0.11% (514 cf natural gas per hour). The CO oxidization catalyst results in a pressure drop of 1.7" WC. Presumably a post-SCR NH3 catalyst would present an additional 1.7" WC, resulting in an additional fuel consumption of 880 cf/hr/turbine, or approximately 2.3 MMCF/yr for the project.

BACT determinations typically reflect the base equipment technology utilized for the project and also the operating schedule of the equipment. Because the turbines are operated in a peaking mode (1,330 hours per year max.), the effectiveness of additional control equipment is diminished relative to prime operation gas turbines. The use of a downstream catalyst will also increase NOx emissions that will not be controlled by the SCR, so the addition of the downstream catalyst would jeopardize compliance with the 2.5 ppmv NOx limit.

The applicant consulted with Engelhard regarding the viability of installing an additional oxidizing layer downstream of the SCR to control NH3 emissions. Engelhard advised that they have not successfully installed a post-SCR NH3 catalysts in a simple-cycle gas turbine operation. Engelhard engineering staff in New Jersey, Maryland and Alabama are unaware of any communication with

CURE or its representatives relative to the use of this technology on simple-cycle turbines.

6.c.ii A lower slip limit can also be achieved by increasing the SCR catalyst volume. This approach was selected by Calpine in the permitting of its Towantic facility in Connecticut to meet a 2 ppmv ammonia slip limit. Please specifically evaluate increasing the volume of SCR catalyst to meet an ammonia slip limit of 2 ppmv at the RERC Project.

Response: Additional catalyst layers have not been successfully installed on simple-cycle gas turbines as a means to reduce NH_3 slip. The Towantic facility is a 500MW combined cycle plant utilizing gas turbine technology that differs from the aero-derivative technology that is proposed for the RERC facility. The LM6000 is much more susceptible to increased backpressure. The additional catalyst layer would add between 1" and 2" of backpressure, resulting a fuel penalty of 514 cf/hr to 1028 cf/hr, or 1.37 mmcf to 2.73 mmcf/yr. The presumed benefit from the 3 ppmv reduction of NH_3 (approximately 3,400 lb/yr) is minimal relative to the increased technology cost and increased fuel consumption.

Adding another layer of catalyst fails to address all conditions that can lead to a NH_3 emission excursion. Often, increases in NH_3 emissions are due to NH_3 stratification across the catalyst that results from injectors that become clogged over time or other system degradation that can lead to uneven NH_3 distribution. In light if the numerous circumstances that can lead to either NH_3 or NO_x excursions of extremely low limits, the applicant contends that 5 ppmv NH_3 is a prudent achieved in practice level that helps to ensure the lowest levels of NOx reduction that are achievable for simple-cycle gas turbines.

7. CO BACT

Background

According to the SCAQMD's 2003 Air Quality Management Plan ("AQMP"), the SoCAB, is one of few air basins in the nation that is still classified as nonattainment for carbon monoxide ("CO").[5] The AQMP states that the SoCAB technically achieved attainment in 2002, but the SCAQMD has yet to gain formal re-designation to attainment status for CO from the U.S. Environmental Protection Agency ("U.S. EPA"). (Id.) Until U.S. EPA makes such formal determination, the New Source Review ("NSR") Best Available Control Technology ("BACT") requirements apply to all new sources that emit CO in the air basin, including the RERC Project.

The Application indicates that "uncontrolled CO emissions are guaranteed to be less than 40 ppmv at 15 percent O_2, but often are less than 20 ppmv at 15 percent O_2." (Application, p. 71.) The Application further specifies the use of a CO catalyst to control these CO emissions by approximately 85 percent to 6 ppmv at 15 percent O_2. (Application, pp. 71 and 82.) The Application maintains that the use of a CO catalyst is considered BACT and that the proposed emission rate reflects "recently permitted simple-cycle projects in California, and [is] believed to reflect the lowest achievable emission rates for simple cycle turbines rated above three megawatts." (Application, p. 71.) However, CO emissions of less than 2 ppmv at 15 percent O_2 have been achieved in practice at other simple-cycle facilities.

The CARB has recently released a report summarizing permitting limits and operating experience with NOx control at gas-fired power plants. (CARB 03/04.) This report demonstrates that a number of simple-cycle facilities using GE LM6000 turbines with water injection and SCR (as proposed for the RERC Project) achieve CO emissions of less than 2 ppmv at 15 percent oxygen during source tests, i.e. , the New York Power Authority Hell Gate facility in Bronx, NY; the Calpine Lambie, Creed, and Goose Haven Energy Centers in Suisun City, CA; the Wellhead Power Gates facility in Huron, CA; the Wildflower Energy Indigo facility in Palm Springs, CA; the GWF Energy LLC Tracy Peaker Power Plant in Tracy, CA; and the Gilroy Energy Center Phase I in Gilroy, CA. (CARB 03/04, Appx. B.)

As discussed above, the SCAQMD's BACT Guidelines regard BACT as being "the most stringent emission limitation or control technique which: (1) has been achieved in practice for such category or class of source..." Consequently, considering the operating experience at similar facilities, a CO limit of 2 ppmv should be considered BACT for the RERC facility.

Further, the proposed CO catalyst, manufactured by Engelhard, Inc., is designed to meet, at a minimum, 95 percent control efficiency. (Application, p. 72.) At an inlet CO concentration of 40 ppmv, this catalyst is capable of reducing CO emissions to at least 2 ppmv. Consequently, the RERC Project could guarantee CO emissions to 3 to 4 ppmv at 15 percent O_2, if not lower, and still have an adequate margin of compliance.

Data Requests

7.a Please explain why the source tests for the New York Power Authority Hell Gate; the Calpine Lambie, Creed, and Goose Haven Energy Centers; the Wellhead Power Gates facility; the Wildflower Energy Indigo facility; the GWF Energy LLC Tracy Peaker Power Plant; and the Gilroy Energy Center Phase I do not establish CO BACT for RERC at 2 ppm or less. Please provide supporting data for any of these facilities that you believe do not meet a CO BACT limit of 2 ppm or less.

Response: The test data presented by CARB for the above-mentioned facilities reflect one-time tests that were conducted immediately after the gas turbines and emission control systems were commissioned and do not identify degradation that will occur during the useful life of the integrated SCR / CO oxidization system, or the relationship between NO_x and CO emissions from the water-injected gas turbines. Any demonstration of achievable CO emissions rates must reflect a consideration of system degradation that will occur during the useful life of the catalyst and balance between CO and NOx emissions from combustion sources such as gas turbines. It is reasonable to predict that CO emission rates from the example projects will increase as operating hours accumulate.

As discussed in the preceding response to NH_3 emissions, one must consider the tenuous nature of compliance with permitted NO_x levels. The difference between permitted NO_x levels and measured NOx levels are as low as 0.05 ppmv in the examples cited by CURE. It is conceivable that continued compliance with permitted NO_x levels will be dependent upon alterations to combustion and water injection that will increase uncontrolled CO emission rates into the catalyst.

7.b Is the Applicant willing to accept a COC specifying a maximum CO concentration at a value less than 6 ppmv at 15 percent O_2? If the answer is no, please provide all information and documents that supports a CO BACT limit of 6 ppmv at 15 percent O_2, for the RERC Project.

Response: No, the applicant does not concur that a maximum value of less than 6 ppmv is warranted or that a lower value is demonstrated to be consistently achieved over the useful life of the integrated NOx / CO emission control system. 40 ppmv is the guaranteed uncontrolled CO emission rate for the gas turbines in most operations, but both the turbine vendor and the emission control system vendor indicate that in some circumstances, uncontrolled CO emissions can spike above 40 ppmv and the controlled emission rate guarantee is accordingly at 6 ppmv.

The application is for an SPPE which would result in the issuance of permits to construct and operate the facility by SCAQMD. SCAQMD should be granted the latitude to specify all criteria pollutant emission limits in its permits. Although SCAQMD has not yet petitioned US EPA to designate the SOCAB to be in attainment with federal ambient CO standards, the State of California has reclassified all of Riverside County to be in attainment with state ambient CO standards. The state standards are more stringent than the federal standards. Compliance with the state standards should drive the debate regarding the regional importance of placing more stringent CO limits on the proposed facility.

7.c Are there any unique aspects of the RERC Project that would prevent it from meeting a CO limit of 2.0 ppmv, 3.0 ppmv, or 4.0 ppmv at 15 percent O_2 averaged over 3 hours? If yes, please identify each such constraint and provide all information and documents supporting your claim.

Response: The application is for an SPPE which would result in SCAQMD issuing permits to construct and operate the facility. SCAQMD will also be charged with enforcing the permit. Any interpretation of BACT relative to averaging hours should be left to SCAQMD. SCAQMD prefers to define BACT-related emission rates based upon one-hour averages.

The applicant does not see a reason why an extended averaging period should be considered simply for the sake of defining a lower emission limit. The extended averaging period confirms that the lower rate cannot be achieved continuously during turbine operations. The extended averaging period would be especially problematic for a peaking operation such as that proposed by the applicant. The more stringent limit, even if achievable during extended periods of operation, would not be achievable during the startup period and possibly not during a shutdown period. Typically, permit conditions that specify emission rate limits also include exceptions for the startup period, and in some cases, the shutdown period. If a three-hour average were incorporated into the permit, the exemption periods specified in the permit would cover a significant amount of turbine operations, conceivably exceeding actual operations some days. SCAQMD's ability to enforce the emission rate would be significantly impaired.

There are other practical emissions and monitoring aspects of the selected averaging period. Only a limited number of data acquisition and handling systems have been demonstrated to comply with SCAQMD Rules 218 and 2011, while also demonstrating compliance with the monitoring requirements of 40 CFR 72 and SCAQMD Regulation XXX. All of these regulations specify one-hour averaging periods. The addition of a three-hour averaging period for CO emissions would require modifications to data acquisition software. Both the applicant and SCAQMD would be placed in the position of having to validate the customization.

The use of a three-hour averaging period would create an exception for the field enforcement staff at SCAQMD. Inspectors would have to be trained to review emissions monitoring data for this single facility differently than the data that are generated at numerous other local facilities. The exception creates uncertainty and inefficiency for SCAQMD staff as well as for facility operations staff.

8. COOLING TOWER DRIFT RATE

Background

Cooling towers emit large volumes of low concentration particulate from multiple stacks that often represent a significant mass emission source. In a cooling tower, water is sprayed over contact media, called fill, as air is drawn counter-current or cross-current to the water stream. As the water is sprayed and evaporated, a large distribution of droplet sizes is created. A portion of these droplets, referred to as drift, will become entrained in the exit air stream and leave the cooling tower. These drift droplets and the solids they contain will be deposited downwind of the cooling tower. Inertial impaction devices called drift eliminators are used to control the emission of these drift droplets. High efficiency drift eliminators of modern design can control the drift to less than 0.0005 percent of the cooling tower circulating water flow. These drift eliminators are able to capture nearly 100 percent of the droplets which are larger than 10 microns ("µm") in diameter.

Considering the RERC Project's location in a PM10 non-attainment area, BACT is required for cooling tower emissions. The Application apparently used a drift rate of 0.001 percent for its cooling tower emissions calculations.[6] However, the BACT level on many recently licensed projects for cooling tower drift rate control has been established at much lower rates. The Applicant did not conduct a top-down BACT analysis for the cooling tower, instead selecting a model with a guaranteed drift rate of 0.001 percent with no support or explanation. Because high efficiency drift eliminators are widely used, they should be assumed technically feasible and cost effective for the RERC Project unless the Applicant documents unique circumstances.

The Tesla Power Project[7], Metcalf Energy Center[8], Contra Costa Power Plant Unit 8 Project[9], Delta Energy Center[10], and the Pittsburg District Energy facilities, have been permitted to achieve guaranteed drift rates of 0.0005 percent to 0.0006 percent. The U.S. EPA and other air districts have likewise concluded that BACT for cooling towers is a drift eliminator efficiency of 0.0005 percent to 0.0006 percent. For example, in its comments on the Preliminary Determination of Compliance for the La Paloma Project, U.S. EPA specifically recognized the use of drift eliminators with a drift rate of 0.0006 percent as BACT.[12] These lower drift rates are readily achieved using two layers of drift eliminators, usually of the cellular type. For example, Brentwood Industries and Balcke-Dürr, both suppliers of cooling towers, guarantee drift rates as low as 0.0005 percent, using two-layer, cellular-drift eliminators.

Data Requests

8.a Is the Applicant willing to use a cooling tower with a guaranteed drift rate of 0.0005 percent?

Response: No. The value of 0.0005% is lower by an order of magnitude than what Brentwood Industries publishes in its data. Also as discussed in 8c , the example projects in the Data Request are large combined cycle plants with large cooling towers (most likely all field erected towers). These are unreasonable benchmarks against which to compare RERC because of their much more significant cooling tower impact.

8.b If the answer to Data Request 4.a is yes, please provide the specifications, i.e. manufacturer, model, engineering design parameters, etc., for the proposed cooling tower.

Response: No documents are required based on our response to 8a.

8.c If the answer to Data Request 4.a is no, please justify the choice of a drift rate of 0.001 percent. Please identify any constraints to the use of a drift eliminator that would achieve a drift rate of 0.0005 percent and support with vendor information, reports, and other sources. Please provide all documents that support your response.

Response: All of the projects cited in the Data Request are large combined cycle projects with large cooling towers that are essentially in full-time operation with a much higher duty. For the RERC, a simple cycle power plant that operates a total of 2,660 hours combined from both units, and with a cooling tower heat duty limited to the chiller and lube oil cooling, the impact of its cooling is significantly less. Maximum potential daily PM emissions are less that 0.5 lb, based upon an operating schedule of 24-hours. Actual daily operating hours will typically be significantly less and annual PM10 emissions from the cooling tower are considered to be insignificant by permitting authorities. Therefore, for a small occasional duty cooling tower, we do not believe the additional cost and complication are justified. . Small packaged cooling towers (unlike the large combined cycle towers quoted above) such as the one being used on RERC can not accommodate additional drift eliminators as suggested by CURE. Small cooling towers like the one being used for the RERC are sold as standard package sizes and the addition of additional drift eliminators would require customized changes to the unit that the factory is not set up to manage. Also, it would require special testing to verify performance, and most likely would lead to a larger cooling tower. This would result in significant cost and schedule impacts and would not be justified for a cooling tower of this size. It should be noted that the Evapco cooling tower being provided for this project does in fact have drift eliminators. Drift rate for the RERC cooling tower is guaranteed to 0.001% of the recirculated water rate, but will likely achieve lower values. These values are very typical for cooling towers of this size. For additional information and photos, you may visit the Evapco website at www.evapco.com and open their Product Brochures tab. Then go to the AT type cooling towers, page 4.

9. CONSTRUCTION EMISSIONS

Background

On June 3, 2004, CURE received a CD-ROM entitled "Riverside Energy Modeling Files 04/30/04". This CD-ROM contains modeling input/output files for ambient air quality dispersion and health risk assessment modeling for the construction and operational phases of the RERC Project. The CD-ROM does not contain any files supporting the construction and operational emissions calculations reported in the Application summary tables nor does it contain any of the emission calculations contained in the Application, Appendices 6.1-A through 6.1-J. We understand that the Applicant is currently revising the air quality and health risk assessment modeling for the RERC Project based on data requests by CEC staff.

Data Requests

9.a Please provide an electronic copy of all construction (site, transmission line, substation) and operational emission calculations. Please include the "CEC-approved spreadsheet," used to calculate combustion emissions from construction equipment. (See Application, p. 84.)

Response: Electronic versions of all construction emission calculations are being submitted in conjunction with the applicant's responses.

9.b Please provide input/output files for ambient air quality dispersion modeling and health risk assessment for the construction and operational phases of the RERC Project.

Response: Input/output files have been delivered to CURE and CEC on June 14, 2004 and again on June 24, 2004.

9.c The construction emissions estimates as currently presented in the Application appear to have omitted pile-drivers, a major source of diesel exhaust emissions. (See Application, Appx. 6.1-D.) Pile drivers are typically used to construct the foundation for the plant, particularly for the turbine pads. Please include exhaust emissions from pile drivers in the revised construction diesel exhaust emission estimates.

Response: Pile drivers are not required because no piling is required for any of the foundations given the site conditions. This conclusion is consistent with the geotechnical report. Therefore exhaust emissions from pile drivers need not be included.

10. CONSTRUCTION MITIGATION

Background

The Application states that "[e]nvironmental impacts will be mitigated through CEC-specified requirements and good management practices" and lists four mitigation measures that "may be applicable for the project." (Application, pp. 88/89.) This statement does not represent a binding obligation to implement any particular construction mitigation . The CEC must specify mitigation measures to be implemented and identify the extent to which they can be effective and reduce a certain impact.

The few mitigation measures specified in the Application are too general, e.g., "[w]ater will be applied to the construction site to reduce fugitive emissions." Any mitigation measure must be specific and contain clear performance goals to be enforceable. In particular, the CEC must specify in a mitigation plan those mitigation measures that were assumed to calculate construction emissions. For example, the fugitive dust emission estimates from onsite vehicle travel on unpaved roads assume 90 percent dust suppression control efficiency. The CEC must specify in its mitigation plan how this control efficiency will be achieved, i.e., the frequency of watering.

Data Requests

10.a Please develop a detailed construction mitigation management plan that specifies all mitigation measures to control diesel exhaust and fugitive dust emissions that will be implemented for construction of the RERC Project generating station as well as for construction of the transmission line and substation.

Response: The information contained in the SPPE addresses construction mitigation.

PUBLIC HEALTH

11. CONSTRUCTION EMISSIONS HEALTH RISK ASSESSMENT

Background

The Application presented a screening level health risk assessment for diesel exhaust emissions from construction with the Hotspots Analysis and Reporting Program ("HARP") published by the California Air Resources Board ("CARB"). The Application states that the HARP model results "reflect a 70-year lifetime exposure. The model results were divided by 70 in order to more accurately reflect the impacts of a short-term project." The Application compares the results to a significance threshold of 10 in one million and concludes that "health risks attributed to the construction projects with mitigated emissions are well below a level of significance." (Application, p. 223.) There are several problems with this approach and, consequently, the conclusion of non-significance.

First, the use of a shorter exposure duration, such as one year, is inappropriate because the unit risk factor for diesel exhaust is based on a lifetime exposure of 70 years. Any subdivision below a lifetime risk is inconsistent with the assumptions used to develop the unit risk factor. An intense, short-term exposure, such as occurs during construction, cannot be spread out over a 70-year period. Public agencies charged with protecting public health do not allow such risk dilution.

For example, the California Air Resources Board's ("CARB's") risk management guidance for diesel-fueled engines recommends the use of an exposure duration of 70 years, regardless of the actual duration of a project (CARB 10/00, [13] p. IV-2.). This policy has been adopted by air pollution control districts charged with implementing diesel exhaust risk reduction policies. The SCAQMD's NSR toxic air contaminants rule, Rule 1401, also requires a lifetime exposure duration for cancer risk assessment. This rule stipulates that "The risk per year shall not exceed 1/70 of the maximum allowable risk specified in (d)(1)(A) or (d)(1)(B) at any receptor location in residential areas." (SCAQMD Rule 1401, § 1401(d)(4).) This is equivalent to a 70-year exposure duration for short-term exposures, expressed in terms of the significance threshold.

The Bay Area Air Quality Management District ("BAAQMD"), another major California air pollution control district, follows the same general policy as the SCAQMD. The BAAQMD has a general Risk Management Policy (BAAQMD 2/3/00[14]) applicable to all types of sources and pollutants, as well as a Diesel-Fueled Engine Risk Management Policy, applicable to diesel engines. (BAAQMD 1/11/02.[15]) Both of these policies require that any exposure to a carcinogen, no matter how short, be treated as though it were to continue for 70 years. Both of these policies stipulate: "The project is acceptable if the annual emissions associated with the project would result in an incremental cancer risk equal to or less than 1.0×E-06 (one in one million), were the exposure to continue for 70 years." [Emphasis added.] These policies are applied when estimating cancer risks from short duration events, such as construction and emergency diesel generators. See, for example, the risk assessment of construction emissions associated with a modification of the Valero Benicia Refinery.[16]

The Office of Environmental Health Hazard Assessment ("OEHHA"), the California agency responsible for developing health risk assessment guidance that is followed by other agencies, has long been concerned about the inappropriate use of short-term exposure durations when assessing cancer risk. OEHHA has published guidance that requires a 70-yearexposure duration, but allows evaluations for 9 years and 30 years.[17] Diesel emissions during construction typically result in significant health risks when evaluated using an exposure duration of 9 years, the minimum allowed by OEHHA guidance.

Second, the significance threshold of 10 in one million used by the Application applies to projects that are constructed with BACT for Toxics ("T-BACT"). (SCAQMD Rule 1401, § 1401(d)(1)(B).) The Application contains no discussion of construction mitigation measures that would constitute T-BACT. Consequently, the CEC must require either a mitigation program which complies with T-BACT requirements as set forth in SCAQMD Rule 1401, or apply the significance threshold of one in one million specified in SCAQMD Rule 1401 at (d)(1)(A) for projects constructed without T-BACT.

And finally, the Application's statement that "model results were divided by 70 in order to more accurately reflect the impacts of a short-term project" appears to be inconsistent with the health risk analysis summary reported in Table 6.8-3. This table reports a Maximum Individual Cancer Risk ("MICR") of 6.22×10^{-7}, the same figure as the result reported from the HARP model run. (Application, Table 6.8-3, and Appx. 6.1-J.) If, in fact, the Application inappropriately used an exposure duration of only one year it would have substantially understated the true cancer risk of Project construction to off-site receptors. In this case, the actual estimated MICR would be 5.6×10^{-6} for a 9-year[18] and 4.4×10^{-5} for a 70-year exposure[19], respectively. Either MICR would exceed the significance threshold of one in one million for projects constructed without T-BACT; the 70-year exposure would also exceed the T-BACT threshold of 10 in one million.

Data Request

11.a Please clarify whether estimated health risks from construction diesel exhaust emissions were, in fact, adjusted by a factor of 70.

Response: Only the cancer risk assessment was adjusted to reflect the shorter duration period.

11.b If the answer to Data Request 7.a is yes, please revise the construction emissions health risk assessment to reflect a 9-year, 30-year, and 70-year exposure, consistent with agency guidance.

Response: Adjustments made to the risk assessment to reflect the short duration of the project were made in accordance with CEC guidance. The Office of Environmental Health Hazard Assessment ("OEHHA") health risk assessment guidelines that specify the 70-year exposure period, as well as the alternative 9-yaer and 30-year periods were developed specifically for the permitting of new or modified stationary sources and for use in the Air Toxics Hot Spots Program. The guidelines were not intended to be used to address the unique characteristics of construction projects and other projects of very short duration. Page 1-2 of the guideline clarifies OEHHA's intent. Page 8-4 of the guideline document clarifies that OEHHA recognizes the shortcomings of using the guidelines for short-term projects and that OHEA is investigating alternative assessment methodologies for extremely short-term exposures. OEHHA does not anticipate issuing guidelines for short-term exposures in the immediate future.

In light of OEHHA's stated intent for the its existing assessment guidelines and in light of the absence of alternative OEHHA guidance for construction project risk assessment guidance, it appears that CEC's practice of allowing short-term exposure adjustments is warranted. Alternative risk calculations of 9-year, 30—year and 70-year exposures to the construction project are not warranted.

11.c Please specify all construction mitigation measures (in a construction mitigation plan) that would justify using the T-BACT significance threshold of 10 in one million. Or alternatively, evaluate health risks from RERC Project construction compared to the significance threshold of one in one million for projects constructed without T-BACT.

Response: The discrepancies on pages 103 and 224 of the application report identified by CURE are typographic errors. CURE is correct in its assertion that the MICR threshold for the construction phase of the project is 1.0E-6, rather than 10.0E-6 as stated in the report. The MICR attributed to construction operations is correctly stated at 6.22E-7. It should be noted that the stated MICR reflects the highest offsite concentration levels that are modeled for the project. These concentrations are all at fence line receptors. Actual concentrations at occupied properties beyond city property and beyond inhabitable land are expected to be significantly lower than those used to determine MICR.

CURE also identified a discrepancy regarding the chronic hazard index as stated in the report. The actual chronic hazard index is 0.0215, rather than 0.00215 as stated in the report.

12. AQUEOUS AMMONIA TRANSPORT

Background

The RERC Project will have a 12,000-gallon storage tank with 19-percent aqueous ammonia on site. The Application performed an aqueous ammonia hazard assessment to determine offsite impacts to the public and found that the toxic endpoint for a 12,000-gallon aqueous ammonia release would be approximately 0.2 miles from the point of release. The Application concluded that there are several small businesses but no residential or sensitive receptors within this 0.2-mile worst-case release radial impact area. (Application, p. 221.)

The Application did not evaluate the potential hazards associated with transportation of the aqueous ammonia. There will be a heightened risk along the transportation route and, in the event of an accident that ruptures the tanker, people on either side of the transportation corridor could be harmed. Several schools and an assisted-care facility are located along Jurupa Avenue to the west of the RERC Project. The Application did not specify a preferred transportation route that would avoid transportation through Riverside and would minimize potential impacts to these receptors.

Data Requests

12.a Please identify the least hazardous transportation route.

Response: The preferred route is along Van Buren, either from Hwy 60 or Hwy 91 depending on which way the load is coming. We do not believe that there are any schools along this route. It may be that CURE has inadvertently confused Jurupa Road in Riverside County with Jurupa Avenue in the City of Riverside close to the project.

12.b Is the Applicant willing to accept a COC, requiring transportation of aqueous ammonia along the least hazardous transportation route?

Response: Yes, recognizing that if this route is temporarily unavailable, an alternate route would be used.

CURE May 26 Data Requests

Remark:

Cooling tower is using reclaimed water; wastewater treatment plant is also source of aerosolized microorganisms. Cumulative emissions from project + WWTP could pose significant public health impact. CEC guidelines on legionella.

Response:

The applicant will conform to appropriate CEC-imposed operating requirements intended to prevent the potential formation of legionella organisms, pursuant to CEC's guidelines. CEC has published draft guidelines pertaining to biocide and legionella control for wet cooling towers similar to those proposed for this project. Components of these guidelines will be reviewed with CEC staff to determine the appropriate control measures for this particular project. As such, potential biological and legionella related risks would be mitigated through the use of various CEC guideline control measures. These control measures may include application of appropriate biocides, proper maintenance and operations and periodic back-flushes. The applicant is not aware of any approved methodologies for ascertaining biological and legionella related risks from small cooling towers or wastewater treatment plants.

Remark:

NOx BACT is 2ppmv averaged over one hour instead of 2.5 ppmv.
CO catalyst designed to meet 2 ppmv instead of 6 ppmv.

Response:

The applicant is aware of only one simple-cycle gas turbine project that is permitted to be constructed at a NO_x standard of 2.0 ppmv. The project, to be located in Lowell, Massachusetts, has not yet been constructed and cannot be used to objectively determine if the suggested limit of 2.0 ppmv is achievable. Additionally, it is unclear if the construction permit, or the potential operating permit would contain allowable exception to the standard during certain operating conditions.

The only objective data available to make a BACT determination lies in projects that have been constructed and operated for a significant portion of their expected catalyst life. The most stringent NO_x level that has been imposed on simple-cycle gas turbines that have actually been constructed and operated is 2.5 ppmv, measured over periods of one to three hours. Examples include the recently permitted Calpine peaker projects, the Hell Gate project in New York and the Wallingsford Energy project in Connecticut. The NO_x limits for these projects are accompanied with NH_3 limits of 6 ppmv to 10 ppmv. The proposed RERC project will be subject to a much more stringent NH_3 limit of 5 ppmv.

CARB summarized field test results for the above-mentioned projects in its draft report to the legislature, dated March 2004 indicates that compliance with the permitted 2.5 NO_x ppmv limit is only marginal. The Hell Gate project is at 2.3 ppmv NO_x and the Calpine test results are as high as 2.45 ppmv. These results reflect relatively new systems and do not present data which would indicate that a more stringent standard of 2.0 ppmv NO_x can be achieved or maintained as the catalysts and NH_3 injection systems age. Because of the relationship between NO_x, CO and NH_3 emissions from simple-cycle gas turbines, continued compliance with the 2.5 ppmv NO_x limit will likely result in increased CO and NH_3 emissions as the systems age.

An additional and more detailed comment relative to CO emissions is included in CURE's first set of data requests. The Applicant's response relative to CO BACT is included in responses to that data request.

Remark:

Due to incomplete combustion, startup produces high concentrations of acrolein, aldehydes, etc. Not clear whether startup were included in health risk assessment.

Response:

The health risk assessment contained in the SPPE application reflects 100% operating load with HAP destruction to be achieved by the oxidization catalyst. The resulting acute hazard index is 0.00596. If no HAP destruction were assumed, the resulting acute hazard index for normal operations would be 0.0397. The SPPE application incorrectly implies that the index without control is 0.0015.

Unlike large frame industrial turbine technology, aero-derivative gas turbines are designed to start quickly. Periods of incomplete combustion are brief and their impact on acute risks is minimal. Data contained in US EPA's AP-42 indicate that HAP emission rates at low loads can exceed HAP rates at high loads ranging from 0% for some compounds to approximately 340% for formaldehyde. The turbine vendor has also confirmed that for brief periods, HAP emissions can occur at higher concentrations during startup. The vendor advises using CO as a surrogate to estimate the short-term emission trend for organic HAPs such as acrolein and formaldehyde. Appendix 6.1-B of the SPPE application contains a CO emission curve for the 10-minute startup period. The curve indicates that CO concentrations during the first seven minutes of startup can be as high as 180 ppmv, versus estimated typical uncontrolled CO rates of approximately 40 ppmv, or a 350% increase.

Based upon the data presented in AP-42 and by the gas turbine vendor, and using the acute risk index for maximum uncontrolled operations, one can estimate the acute risk during turbine startup. If one assumes a 400% increase in HAP emissions for seven minutes, the overall risk during the full startup hour is 135% higher than the risk from normal uncontrolled operations ([(400% x 7 minutes) + (100% x 53 minutes)]/60 minutes). The resulting acute health index for a startup hour is 0.0536 (0.0397 x 135%). The resulting index is well below established CEC and SCAQMD thresholds of significance. The resulting index is also likely to be slightly overstated because it reflects the assumption that fuel consumption rates during the initial seven-minutes of operation are at 100% of rated capacity, that ammonia emissions exist during the first ten minutes of operation, and that no reductions in HAPs occur from oxidization during the first full hour of operation. None of these conditions is likely to exist.

RESPONSE TO CURE DATA REQUESTS SET 1

REQUEST #1

Plant Configuration Study – Initial Results – Addendum 1

July 1, 2003

Robert Gill, Principal Electrical Engineer
Riverside Public Utilities
3900 Main Street
Riverside, CA 92522

Subject: Plant Configuration Study – Initial Results – Addendum 1

Dear Robert:

This letter is an addendum to our earlier evaluation of alternate configurations for the Acorn Generation Project (POWER Engineers letter 34-219 dated June 30, 2003). In this addendum we have included a 1x0 LM6000 configuration using the same methodology and assumptions as the previously evaluated options. The 1x0 LM6000 results contained herein differ from some of the previous results due to the cost estimate not including the transmission line, no contingency being applied, slightly different operating conditions, and some differences in system configurations. For completeness, we have also included the body of the original letter too.

As requested at our project meeting on June 24, POWER Engineers has evaluated several alternate configurations for the Acorn Generation Project. The purpose was to evaluate options for a plant of 100-150 MW operating on a 5 day a week, 14 hours per day schedule with nightly shutdowns. We have developed some initial results and recommendations for your consideration.

Evaluated Options

We looked at a combination of combined cycle and simple cycle options. The combined cycle plants offer the advantage of being the most efficient configuration. The simple cycle options, using the largest aeroderivative combustion turbines, potentially offer a lower cost approach since they avoid the capital cost and operating complexities of the steam plant. We evaluated the following options:

- General Electric LM6000 SPRINT 1x1 simple cycle (with the steam turbine sized for 2x1)
- General Electric LM6000 SPRINT 2x1 combined cycle
- General Electric LM6000 SPRINT 1x0 simple cycle
- General Electric LM6000 SPRINT 2x0 simple cycle
- General Electric LM6000 SPRINT 3x0 simple cycle
- Pratt & Whitney FT8-3 TwinPak Plus 2x0 simple cycle
- Rolls Royce Trent 60 2x0 simple cycle

POWER Engineers, Incorporated
124 Washington Ave., Suite E
Point Richmond, CA 94801
Phone (510) 215-0638
Fax (510) 215-0631

Note that both of the combined cycle options utilize a small amount of supplementary firing in the Heat Recovery Steam Generator to increase the temperature of the gas exiting the combustion turbine to boost the output and efficiency of the steam plant.

Evaluation Process

The overall process was to develop the generation capacity, heat rate, operating costs, and capital costs for each option. We used the following inputs and assumptions for our evaluation.

1. We obtained performance data from General Electric (GE), Pratt & Whitney (P&W), and Rolls Royce (RR) for their respective engines at the Riverside site conditions of 730' elevation and 100 °F. The vendors were asked to make their own assumptions on inlet and outlet losses assuming they would provide the inlet air-cooling and exhaust gas treatment systems as a package. (This is consistent with the bidding strategy we have discussed previously.) In addition, they also provided their own estimates of auxiliary equipment loads.
2. Based on thee inputs, we then ran GT Pro models to develop net generation and heat rate (LHV) values for each configuration. We also used GT Pro to develop cost estimates for relative comparisons.
3. Using these results, we then developed estimates of annual operating costs based on:
   - An operating cycle of 3,640 hours (14 hours/day x 5 days/week x 52 weeks)
   - $4.75/MMBtu gas (HHV)
   - Variable O&M of $3/MWh
   - Fixed O&M of $20,000/MW
   - Ratio of HHV/LHV of 1.11
   - Water cost was assumed to be zero
4. Capital cost estimates were also developed using GT Pro for **relative ranking purposes only**. These estimates are only applicable for relative ranking as they assume "list" price for the engines (more than we would expect in today's market) and have not had a site-specific review as in the case of our earlier estimate for the LM6000 peaking plant. The cost for the 1x1 LM6000 Combined Cycle was estimated to be $25,000,000 less than the 2x1 configuration. These capital costs are for relative comparison purpose and should not be used on an absolute basis as an indicative price without POWER being able to further quantify the cost estimates. Please also note that these cost estimates do not include the cost of the 69 kV transmission line or additional permitting costs that might be incurred with a CEC application.
5. In order to provide a common basis for comparison, a net present value based on 20 years of operation was estimated.

Results

The results of the above evaluation are summarized in the attached table. The heat rate and generation values are essentially final with minor variation expected once the final inlet and outlet combustion turbine equipment performance is known. The financial results are gross estimates. We would expect the final values to change once firm equipment bids are obtained. In addition, due to the available time, the cost estimates that were prepared do not reflect what actual final system configurations might be.

As expected the combined cycle plants offer the best heat rate and corresponding lowest fuel costs (on a per kW basis). The combined cycle plants are also the most expensive to construct on a per kW installed basis. An additional concern for the combined cycle options are that they cannot be dispatched as quickly as a simple cycle plant, and that daily cycling from hot to cold/warm conditions may pose additional operating challenges for both operations and equipment life.

The simple cycle plants are all relatively close together in performance from a financial perspective. The differences between them are smaller than the accuracy of the estimates. That coupled with the believed conservatism in the engine prices, means that we cannot with certainty recommend which is the best option at this time. If other criteria are more important to RPU, then this may alter the above conclusion. Another consideration for the simple cycle plant options is that they are the easiest to construct and thus they clearly support the May 2005 operational date.

Based on the close estimated financial performance of the different options, at this point we recommend the following approach:

1. Proceed with aeroderivative combustion turbines in simple cycle.
2. Obtain firm competitive bids for General Electric LM6000, Pratt & Whitney FT8-3, and Rolls Royce Trent engines. Both the LM6000 and FT8-3 are currently available as dual fuel engines.
3. Develop refined cost estimates for the options.
4. Select the final option.

If on the other hand, you want to focus on a LM6000 based plant, then we would recommend proceeding with a 3x0 simple cycle plant. This would still have the ability to be converted to a combined cycle facility at a later date.

Focusing on a single engine at this point in time is only an option for the LM6000 because of the secondary market that exists for this engine. For either of the two other engines, no such secondary market exists and thus RPU would want to solicit bids from all three vendors to ensure good competitive bids.

We would welcome any comments or suggestions that you and your colleagues have on the cost estimate.

Sincerely,
POWER Engineers, Inc.

David Tateosian, P.E.
Project Manager

DCT:di

cc: Joe Carrasco (RPU)
Dan McCann (RPU)
Jay Keeling (POWER Engineers)
Dale McDonald (POWER Engineers)

Sent Via: Priority Mail

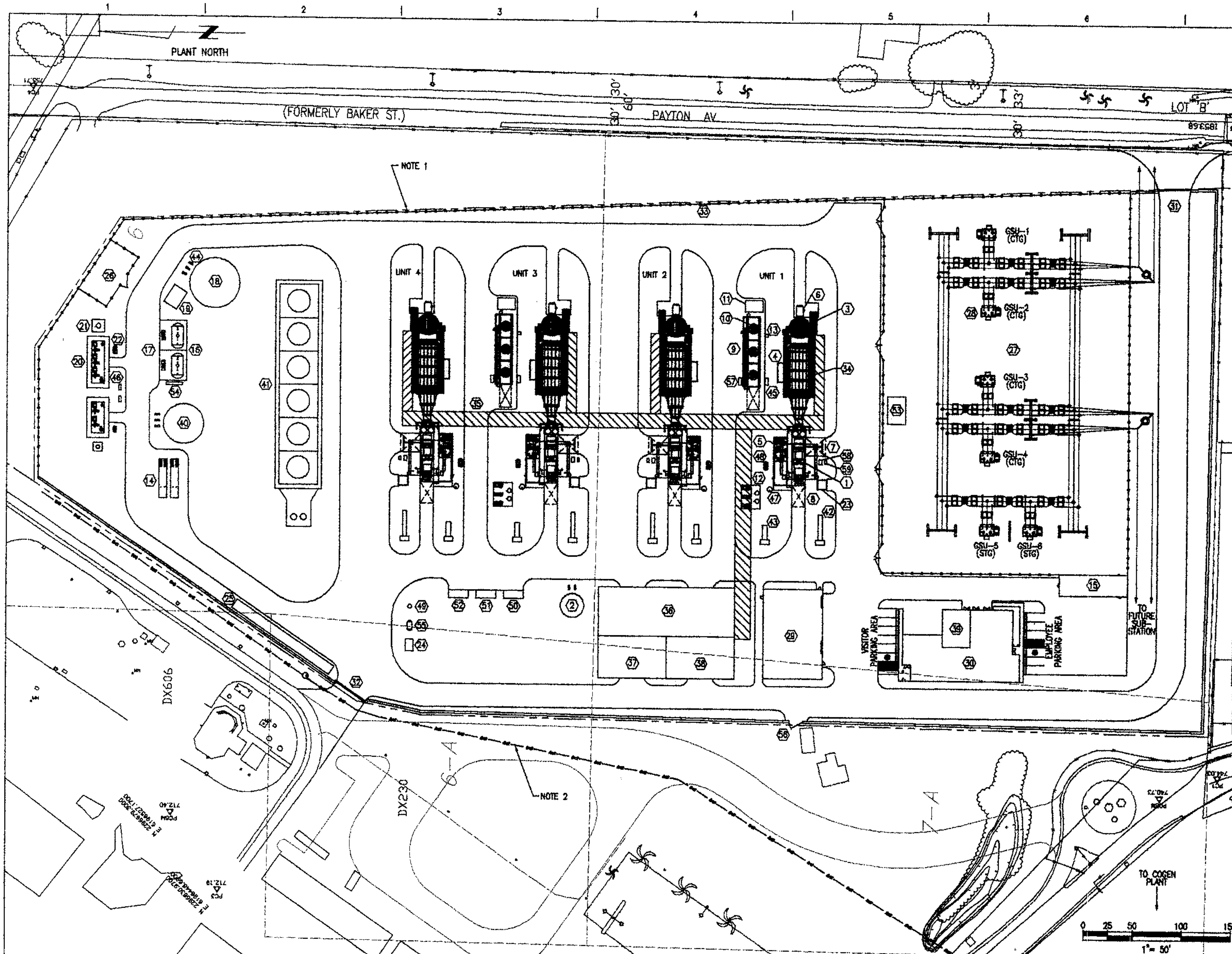
Summary of Evaluation Results

Configuration	Net Output, kW	Net Heat Rate, Btu/kWH LHV	Fuel Cost, $/Year	Variable O&M, $/ Year	Fixed O&M, $/ Year	Total O&M, $/ Year	Total O&M, $/kW	Capital Cost, $	Capital Cost, $/kW	NPV, $/MWh
1X1 LM6000 in CC	64,830	7,295	$9,076,000	$708,000	$1,297,000	$11,081,000	$170	$76,839,000	$1,190	$49.44
2X1 LM6000 in CC	133,650	7,094	$18,196,000	$1,459,000	$2,673,000	$22,328,000	$170	$101,839,000	$760	$42.87
1X0 LM6000 in SC	47,050	8,884	$8,022,000	$514,000	$941,000	$9,476,000	$201	$35,226,000	$749	$49.36
2X0 LM6000 in SC	94,160	8,878	$16,043,000	$1,028,000	$1,883,000	$18,955,000	$200	$63,557,000	$680	$48.32
3X0 LM6000 in SC	141,270	8,876	$24,065,000	$1,543,000	$2,825,000	$28,433,000	$200	$89,990,000	$640	$47.79
2X0 FT8 in SC	109,440	9,715	$20,405,000	$1,195,000	$2,189,000	$23,789,000	$220	$69,165,000	$630	$50.85
2X0 TRENT in SC	112,910	8,808	$19,087,000	$1,233,000	$2,258,000	$22,578,000	$200	$73,618,000	$650	$47.74

RESPONSE TO CURE DATA REQUESTS SET 1

REQUEST #1

Plant Arrangement Combined Cycle
Drawing #M1-4



ITEM	DESCRIPTION	NOTES
1	COMBUSTION TURBINE GENERATOR	
2	CONDENSATE STORAGE TANK & PUMPS (2)	(80,000 gal)
3	EXHAUST STACK	80' HIGH
4	AMMONIA EVAPORATION SKID	
5	CTG AUXILIARY SKID	
6	CEMS SHELTER	
7	TURBINE REMOVAL AREA	
8	GENERATOR REMOVAL AREA	
9	CHILLER PACKAGE	
10	AUXILIARY COOLING TOWER	
11	AUX COOLING TOWER CHEM FEED SKID	
12	AIR COMPRESSOR/DRYER SKID & RECEIVER	3 COMPRESSORS PER 2 CTG'S
13	CTG LUBE OIL COOLING WATER PUMP SKID	
14	DEMINERALIZED WATER TRAILERS	
15	SWITCHYARD CONTROL SHELTER	22' x 75'
16	AQUEOUS AMMONIA STORAGE TANKS (2) AND PUMPS (8)	10' DIA x 19'-0" (12000 gal)
17	AQUEOUS AMMONIA UNLOADING PAD	
18	RAW/FIRE WATER STORAGE TANK	(500,000 gal)
19	FIRE WATER PUMP HOUSE	
20	FUEL GAS COMPRESSOR SKID	
21	FUEL GAS COMPRESSOR BYPASS COOLER	
22	FUEL GAS LIQUID DRAINS TANK	
23	CTG SWITCHGEAR	
24	PROCESS WATER SUMP AND PUMPS	
25	STORM WATER RETENTION/INFILTRATION BASIN	10' x 30'
26	GAS METERING STATION	
27	SUBSTATION	
28	GSU TRANSFORMER (6)	
29	WAREHOUSE	60' x 90'
30	ADMINISTRATION/CONTROL BUILDING	72' x 118'
31	MAIN PLANT ENTRANCE	SLIDING GATE
32	EMERGENCY PLANT ENTRANCE	SLIDING GATE
33	PLANT PERIMETER FENCE (10'-0" HIGH)	
34	HEAT RECOVERY STEAM GENERATOR	
35	PIPE RACK/TRENCH	
36	STEAM TURBINE BAY	
37	WATER TREATMENT AREA	
38	ELECTRICAL ROOM	
39	CONTROL ROOM	
40	DEMINERALIZED WATER TANK & PUMPS (3)	(300,000 gal)
41	COOLING TOWER	
42	4160V MCC W/AUXILIARY TRANSFORMER	
43	480V SAS W/AUXILIARY TRANSFORMER	
44	RAW WATER PUMPS (3)	
45	480V SCR AREA MCC	
46	480V FUEL GAS COMPRESSOR AREA MCC	
47	COIL CONDENSATE TANK AND PUMP	
48	WASTE OIL DRAIN TANK	
49	OILY WASTE COLLECTION SUMP & PUMPS	
50	FLAMMABLE STORAGE	8' x 20'
51	WASTE OIL STORAGE	8' x 20'
52	CHEMICAL STORAGE	8' x 20'
53	TRANSFORMER OIL SUMP	
54	480V BOP COMMON MCC	
55	OIL/WATER SEPARATOR	
56	EQUIPMENT/PERSONNEL ACCESS GATE	SLIDING GATE WITH MAN GATE
57	CHILLER REFRIGERANT DRAIN SUMP	
58	CTG FINAL FUEL FILTER SKID	
59	CTG FINAL FUEL FILTER DRAINS TANK	

LEGEND

PROPERTY LINE
SECURITY FENCE
EXISTING DIGESTER GAS LINE
SECURITY WALL

NOTES

1. APPROXIMATE TOE OF SLOPE
2. ESTIMATED LOCATION OF GAS LINE. (NOT PART OF THE SURVEY).
3. COMBINED CYCLE CONFIGURATION HAS NOT BEEN SELECTED. PROVISIONS HAVE BEEN MADE FOR A 4 x 1, 4 x 2, OR TWO 2 x 1'S.
4. EQUIPMENT SHOWN ON THIS DRAWING IS BASED ON THE BEST AVAILABLE INFORMATION. THIS DRAWING WILL NEED TO BE REVISED BASED ON ACTUAL VENDOR DRAWINGS AND DETAILED DESIGN.

M1-4.dwg

INTER-DISCIPLINE REVIEW

DISC	ARCH	CIVIL	ELECT	HVAC	I&C	MECH	STRUCT
DATE	1/21/04	1/21/04	1/21/04		1/21/04	1/21/04	
INIT	SD	KW	LT		MAC	PR	

REV	REVISIONS	DATE	DRN	DSGN	CKD	APPD
	ISSUED FOR BID	2/12/04	CEA	CEA	JPB	JPB
	ISSUED FOR REVIEW	1/26/04	CEA	LED	JPB	JPB
	ISSUED FOR REVIEW	11/14/03	CEA	LED	JPB	JPB
	REMOVED FUEL OIL TANK	10/15/03	CEA	LED	JPB	JPB
	ISSUED FOR REVIEW	10/6/03	DC	LED	JPB	JPB

REFERENCE DRAWINGS

DSGN	LED	6/20/03
DRN	LED	6/20/03
CKD	JPB	6/20/03
SCALE:	1"=50'	

FOR 22x34 DWG ONLY

POWER ENGINEERS

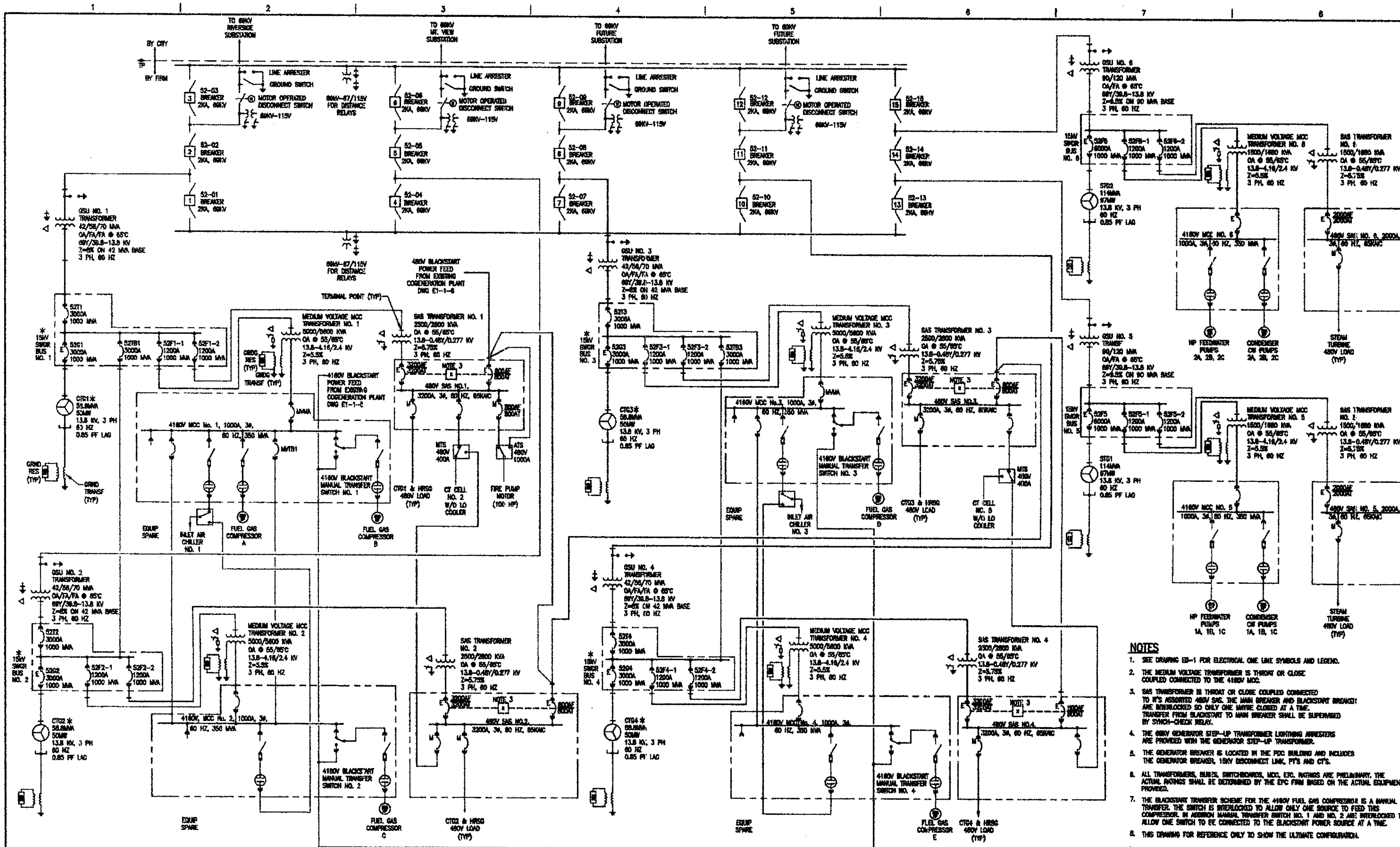
RIVERSIDE PUBLIC UTILITIES
RIVERSIDE ENERGY RESOURCE CENTER
PLANT ARRANGEMENT
COMBINED CYCLE

JOB NUMBER 101414
REV G
DRAWING NUMBER M1-4

RESPONSE TO CURE DATA REQUESTS SET 1

REQUEST #1

Ultimate Combined Cycle
Drawing #E1-4



NOTES

1. SEE DRAWING ED-1 FOR ELECTRICAL ONE LINE SYMBOLS AND LEGEND.
2. THE MEDIUM VOLTAGE TRANSFORMER IS THROAT OR CLOSE COUPLED CONNECTED TO THE 4160V MCC.
3. SAS TRANSFORMER IS THROAT OR CLOSE COUPLED CONNECTED TO IT'S ASSORTED 480V SAS. THE MAIN BREAKER AND BLACKSTART BREAKER ARE INTERLOCKED SO ONLY ONE MAYBE CLOSED AT A TIME. TRANSFER FROM BLACKSTART TO MAIN BREAKER SHALL BE SUPERVISED BY SYNCH-CHECK RELAY.
4. THE 69KV GENERATOR STEP-UP TRANSFORMER LIGHTNING ARRESTERS ARE PROVIDED WITH THE GENERATOR STEP-UP TRANSFORMER.
5. THE GENERATOR BREAKER IS LOCATED IN THE PDC BUILDING AND INCLUDES THE GENERATOR BREAKER, 15KV DISCONNECT LINK, PT'S AND CT'S.
6. ALL TRANSFORMERS, BUSES, SWITCHBOARDS, MCC, ETC. RATINGS ARE PRELIMINARY. THE ACTUAL RATINGS SHALL BE DETERMINED BY THE EPC FIRM BASED ON THE ACTUAL EQUIPMENT PROVIDED.
7. THE BLACKSTART TRANSFER SCHEME FOR THE 4160V FUEL GAS COMPRESSOR IS A MANUAL TRANSFER. THE SWITCH IS INTERLOCKED TO ALLOW ONLY ONE SOURCE TO FEED THIS COMPRESSOR. IN ADDITION MANUAL TRANSFER SWITCH NO. 1 AND NO. 2 ARE INTERLOCKED TO ALLOW ONE SWITCH TO BE CONNECTED TO THE BLACKSTART POWER SOURCE AT A TIME.
8. THIS DRAWING FOR REFERENCE ONLY TO SHOW THE ULTIMATE CONFIGURATION.

* BY CTG VENDOR

E1-4.DWG

INTER-DISCIPLINE REVIEW								
DISC	ARCH	CIVIL	ELECT	HVAC	I&C	MECH	STRUCT
DATE	1/21/04	1/21/04	1/21/04	–	1/21/04	1/21/04	–
INIT	SD	KW	LT	–	MAC	PR	–

REV	REVISIONS	DATE	DRN	DSGN	CKD	APPD
△	ISSUED FOR BD	02/12/04	JMD	LT	MC	LT
△	ISSUED FOR REVIEW	01/26/04	JMD	LT	MC	LT
△	ISSUED FOR REVIEW	09/30/03	AS			
△	ISSUED FOR REVIEW	09/26/03	AS			
△	ISSUED FOR REVIEW	09/23/03	AS			

REFERENCE DRAWINGS

DSGN		
DRN	AS	09/23/03
CKD		
SCALE:	NONE	

FOR 22x34 DWG ONLY

POWER ENGINEERS

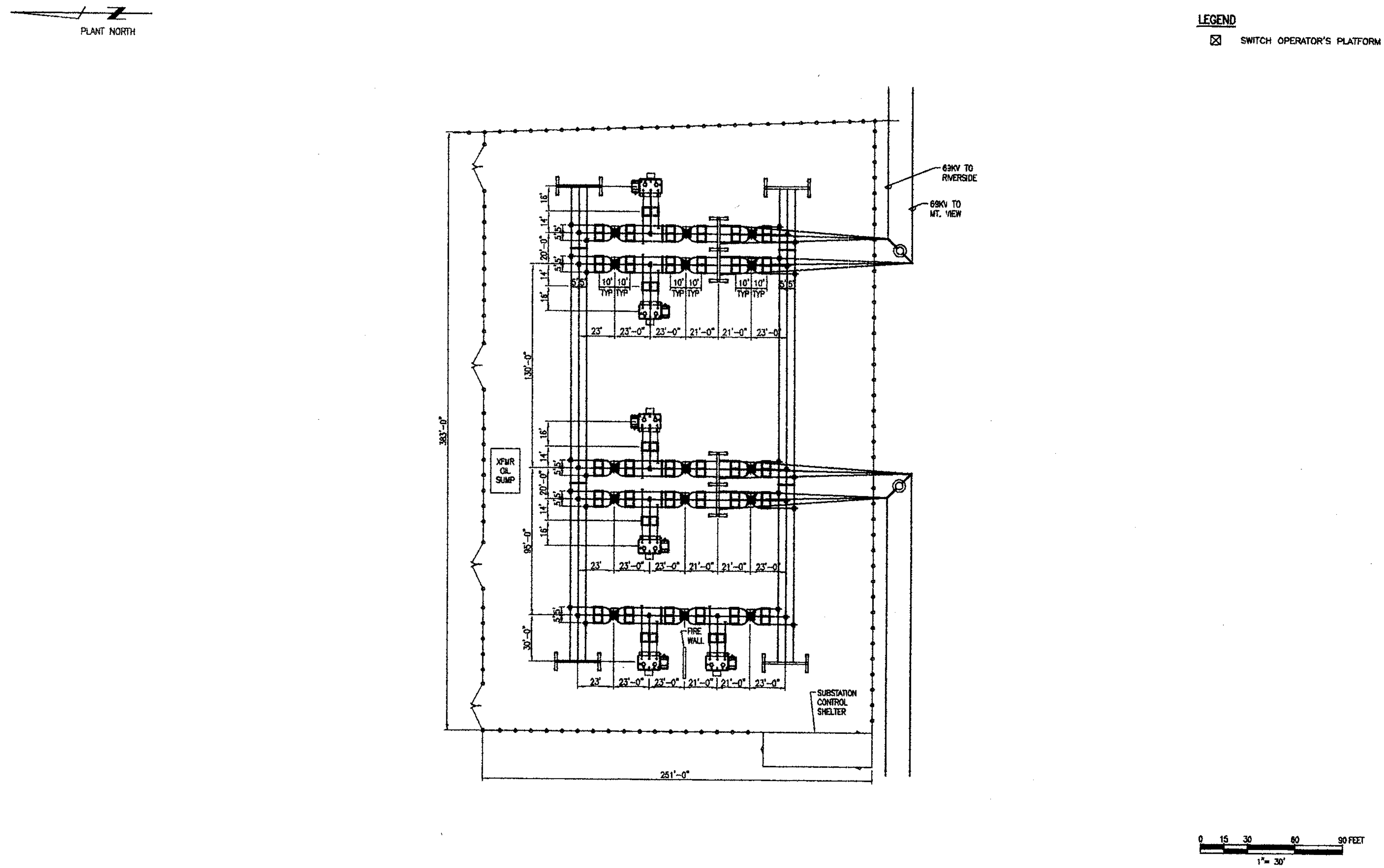
RIVERSIDE PUBLIC UTILITIES
RIVERSIDE ENERGY RESOURCE CENTER
KEY ONE LINE DIAGRAM
ULTIMATE COMBINED CYCLE

JOB NUMBER: 101414
REV: E
DRAWING NUMBER: E1-4

RESPONSE TO CURE DATA REQUESTS SET 1

REQUEST #1

Substation General Arrangement Ultimate Combined Cycle
Drawing #E1-7-3



21relcpl.dwg

INTER-DISCIPLINE REVIEW

DISC	ARCH	CIVIL	ELECT	HVAC	I&C	MECH	STRUCT
DATE	1/21/04	1/21/04	1/21/04		1/21/04	1/21/04	
INIT	SD	KW	LT		MAC	PR	

REV	REVISIONS	DATE	DRN	DSGN	CKD	APPD
B	ISSUED FOR BID	2/12/04	CEA	KVC	JK	JPB
A	ISSUED FOR REVIEW	1/26/04	CEA	KVC	JK	JPB

REFERENCE DRAWINGS

DSGN	CEA	11/17/03
DRN	CEA	11/17/03
CKD	KVC	11/20/03
SCALE:	1"=30'	

FOR 22x34 DWG ONLY

POWER ENGINEERS

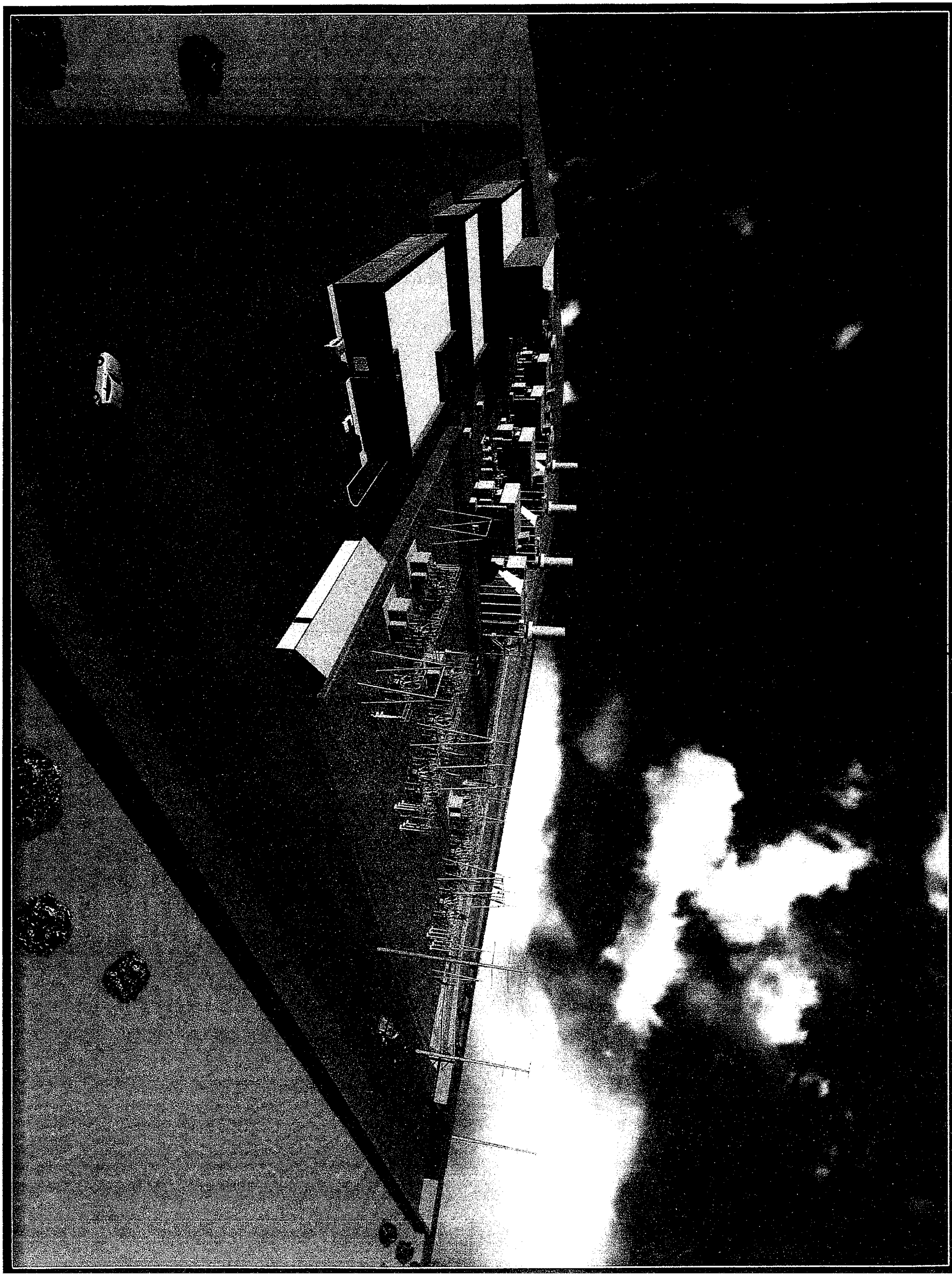
RIVERSIDE PUBLIC UTILITIES
RIVERSIDE ENERGY RESOURCE CENTER
SUBSTATION GENERAL ARRANGEMENT
ULTIMATE COMBINED CYCLE

JOB NUMBER 101414
REV B
DRAWING NUMBER E1-7-3

RESPONSE TO CURE DATA REQUESTS SET 1

REQUEST #1

Visual Simulation Ultimate Combined Cycle



RESPONSE TO CURE DATA REQUESTS SET 1

REQUEST #1

Meeting Notes

Riverside 50 MW Peaker Owners
Acorn Generation Project

RESPONSE TO CURE DATA REQUESTS SET 1

REQUEST #1

Meeting Notes

Riverside 50 MW Peaker Owners
Acorn Generation Project

Subject: Riverside 50 MW OE Project Kickoff Meeting

Attendees:
RPU - Jay Carrasco, Bob Gill, Lyle Hill, Dan McCann, Dave Reading
POWER - Jay Keeling, Karl Lany, Kevin Lincoln, Harry Markwick, Dave Tateosian, Bob Worthington

AUTHORIZATION & BUDGET

This topic was discussed prior to the full meeting. RPU has not yet issued the task order. POWER will continue work on the project and monitor incurred fees.

PWC SITE, WORK PLAN, PROJECT PROCEDURES

PWC is working successfully for everyone. The work plan and project procedures were reviewed. There were some changes and additions to the project procedures. It will be revised and reissued.

LESSONS LEARNED

The Springs Substation project Lessons Learned was reviewed. Major themes were communication, planning, having one team with a common goal, training, and technical issues. These areas will be addressed through project meetings, PWC, allowing time for reviews, review of the specs, review of startup procedures (plus initial training), etc.

POTENTIAL SITES

RPU's plan is to have a new 50 MW peaker operational by May 2005. A second unit is anticipated in 2008. RPU's contract for Baseload power expires in 2010-2011 creating the need for another 50 MW. Thus the plant could ultimately evolve into a 2x1 or a 3x1 power plant. The site layout and conceptual design should keep this in mind.

There are two potential sites: Toro and the Wastewater Treatment Plant. (The Toro site has since been renamed the Jurupa site.) Both sites would interconnect to Mt. View substation via a 69 kV transmission line. The Jurupa site is unimproved and is slightly rolling. The Wastewater Treatment Plant site is flat with a few piles of large boulders. RPU provided an aerial photo showing the physical arrangement of the sites. This has been posted to PWC.

In 2006, a 230/69 kV substation is planned for the Wastewater Treatment Plant. If the power plant is located at this site too, it will still initially interconnect to the Mt. View substation and then later connect to the new substation. The layout at the Wastewater Treatment Plant also needs to bear this in mind.

Of the two sites, the Wastewater site is preferred because of the availability of water, a ready receiver for any wastewater, the presence of the existing recip plant that can be used for black start, and other synergies. The only concern with this site is whether the recip plant and the new peaker can be kept separate for air permitting purposes. Karl Lany has received initial indications that this will be the case but will follow-up to obtain a final determination. If the final answer is yes then the Jurupa site will be dropped. Otherwise the Jurupa site will need to receive further consideration. Once a final site is selected, a site survey and geotech will be required. (The latest status on this issue is that SCAQMD is still mulling over the issue of segregating sites. They claim that they have not been faced with this issue before and want a legal interpretation. Karl is reminding them daily that we need a swift response.)

Given this status, a substantial portion of the Task 2 Site Selection activities may be a moot point if the Wastewater site is selected. This will result in that task's associated budget not being needed.

RPU has requested that POWER perform a short circuit analysis that was not included in the scope of the original work plan. POWER will generate a Work Scope Variance to document the scope change. It is anticipated that the study can be performed within the existing project budget if the Wastewater site.

Kevin Lincoln will research the need for a Storm Water Permit and Plan. (After the meeting Kevin did research this and we will need to permit with the Regional Water Quality Control Board (RWQCB) and develop a Storm Water Plan.)

Either site will need to be enclosed in a 10' high architectural brick wall around the perimeter. There was some discussion of when to build the wall (before plant construction starts or after the plant is completed) and how much to enclose (the current 50 MW peaker or a larger long-term plant site).

Jay Keeling and Bob Worthington will proceed to define the switchyard and interconnect.

FRAMATOME STUDY

No major comments on the study. Everyone agreed that given that RPU is adding 50 MW now with a subsequent addition of another 50 MW in three years, that going with a single 50 MW class machine is the right approach. If the subsequent addition 50 MW was not going to take place, then one of the other options may have been more attractive to provide some redundancy. The Framatome study has been posted to the PWC. Dave will be meeting with Framatome to discuss the study with them. (This was done on 5/9.)

EDS STUDY

RPU provided the conceptual drawings that EDS has developed showing a switchyard for a 2xLM2500 plant and the transmission routing. These have been posted to the PWC. RPU is also expecting enough drawings for the 230/69 kV substation to get through the planning phase, e.g., transmission line routing, substation GA, etc.

ENGINE SELECTION

Discussed the options for engines to use for the project. The project must be below 50 MW to avoid CEC permitting. Five options were considered:

Alstom GTX-100 – eliminated since this engine is more akin to a Frame engine and better suited to a combined cycle plant. It has a poorer heat rate than the LM6000.
GE LM6000 – this is the preferred engine since it meets the MW criteria, has a good heat rate, there are many in service, and there are many available in the marketplace.
P&W TwinPak – not as good a heat rate as the LM6000
Rolls Royce Trent – eliminated since there are only two in North American service. The water-injected version of the engine also exceeds 50 MW.
Recips – eliminated since turbines are better suited to the future expansion plans

POWER will develop a justification for selecting the LM6000. This is not a sole source to GE since other sources for "new and in the box" LM6000s will be considered.

Bids will be solicited for an engine/SCR package so that the package supplier will be responsible for guaranteeing the overall emissions performance. Bidders will be allowed, as an option, to bid only supplying an engine.

CONTRACTING STRATEGIES

The project was broken into two scopes:

- Transmission line - RPU's typical approach for transmission lines is design-bid-build (DBB). This is the approach that will be used for this project too.
- Power plant and Switchyard – this will be handled as one combined scope of work and will be performed as either EPC or DBB. If the project schedule allows

sufficient time, the preference is for DBB. Otherwise the fallback is to EPC with a detailed spec. In developing the schedule, 4 months will be allowed for the time from bid spec release to award.

TECHNICAL ISSUES

- The site will be manned and capable of remote dispatch
- Aqueous ammonia will be used for the SCR
- 1,500-2,000 hours/year of operation
- No single failure to take the whole plant down – within reason
- Provide spares where its reasonable to do so
- Natural gas will be supplied from a 565 psig (nominal) 30" line that crosses through the northwest corner of the Wastewater Treatment Plant.
- Fiber for telecommunications will be installed by June 2004 and thus will be available for the plant.
- Automated motor operated line switches will be used at each end of the interconnecting transmission line
- RPU uses a 900 MHz spread spectrum system
- Horiba CEMS will be used
- The DCS will use Wonderware tying the Wastewater Treatment Plant recip plant, Springs Substation GE-10 plant, the Operations Center at 2911 Adams Street, and the new power plant together for monitoring and dispatch.

SITE VISIT

Following the meeting, a site visit to the Wastewater Treatment Plant recip plant and site for the new plant took place. This site is very flat with several large piles of large boulders. It may be possible to layoput the site so all of the piles do not need to be excavated.

ACTION ITEMS

- Update names and contact info in the Procedures Manual – Dave Tateosian
- Obtain answer from SCAQMD on segregating the peaker plan and the wastewater recip plant for air permitting purposes – Karl Lany
- Develop LM6000 selection justification – Dave Tateosian
- Revise project schedule to show EPC and DBB timeline options – Dave Tateosian
- Generate an RFI requesting wastewater plant information – Harry Markwick
- Generate an RFI requesting RPU's preferred equipment – Harry Markwick

- Develop a Work Scope Variance for the added short circuit study – Jay Keeling
- Research the need for a Storm Water Permit and Plan – Kevin Lincoln
- Site Survey and geotech analysis after site selection is complete – Kevin Lincoln

POWER ENGINEERS

May 19, 2003

Robert Gill, Principal Electrical Engineer
Riverside Public Utilities
3900 Main Street
Riverside, CA 92522

Subject: RPU Engine Selection Evaluation

Dear Robert:

As requested at our joint kickoff meeting on May 6th, POWER Engineers has prepared an evaluation of the engines that are candidates for the Riverside peaker project. Based on our review, we are recommending that Riverside proceed with using a General Electric LM6000 SPRINT combustion turbine.

Thank you again for the opportunity to support your efforts to provide Riverside with a reliable supply of electricity. Please feel free to contact us if you and your colleagues have any comments or suggestions.

Sincerely,
POWER Engineers, Inc.

David Tateosian

David Tateosian, P.E.
Project Manager

DCT:di

cc: Joe Carrasco (RPU)
Dan McCann (RPU)
Jay Keeling (Power Engineers)
Harry Markwick (Power Engineers)
Dale McDonald (Power Engineers)

Sent Via: Priority Mail

PRM 34-182 (05/19/03) 516590-01/di

POWER Engineers, Incorporated
124 Washington Ave., Suite E
Point Richmond, CA 94801
Phone (510) 215-0638
Fax (510) 215-0631

RIVERSIDE PUBLIC UTILITES

50 MW PEAKER PLANT ENGINE EVALUATION

MAY 19, 2003

PRM 34-182 (05/19/03) 516590-01/di

POWER ENGINEERS

PROJECT BACKGROUND

Riverside Public Utilities (RPU) has embarked on a project to add an additional 50 MW of generating capacity by May 2005. This project will supplement the recent 40 MW Springs Substation project and result in enough capacity to support the City's immediate needs in the event that all outside sources were lost. In addition, the additional generation will help the City to cost effectively supply energy on peak demand days when purchased power prices are at their peak.

Longer term, RPU expects to need an additional 50 MW by May 2008. Beyond that, it may be necessary add additional base load generating capacity when the current base load energy supply contract expires in 2010.

This series of needs has led RPU to pursue the following long-term strategy:

- Add generation in increments of 50 MW or less to match load growth and be able to permit the projects locally[1]
- Add 50 MW to provide 1,500-2,000 hours annually of peaking capacity by May 2005.
- Develop this project anticipating adding another 50 MW of peaking capacity at the same site after at least 3 years
- Securing replacement base load energy in 2010 through new contracts or new base load generation. The new base load generation capacity could be provided by conversion and expansion of the existing peaking capacity.

Thus the new power plant site and design is being developed to accommodate the addition of a second unit with subsequent conversion to a 2x1 or 3x1 combined cycle plant[2].

---

[1] New power plant projects or additions to existing ones of greater than 50 MW net generation require permitting through the California Energy Commission, which can be lengthier and more costly than permitting through local agencies.

[2] The nomenclature 2x1 refers to a combined cycle plant with two combustion turbines where the waste heat is utilized to generate steam to power a single steam turbine providing a total of three generators.

INITIAL ENGINE STUDY

With the above strategy in mind, RPU commissioned Framatome ANP to conduct a study[3] that served to compare engines of three different sizes – 10 MW, 25 MW, and 50 MW - and their relative installed cost. The options considered, and resulting net generation and capital cost[4], were:

1. Four General Electric GE-10 combustion turbines (37.2 MW net, $41.1 million)
2. Two General Electric LM2500 combustion turbines (40.8 MW net, $41.4 million)
3. One General Electric LM6000 combustion turbines (42.5 MW net, $36.6 million)

The conclusion of the study was that using a single 50 MW class engine was the most cost-effective approach. This is based on this configuration having both the lowest capital and life cycle costs. This is largely due to the increasing efficiency of the larger engines and resultant lower heat rate along with the reduced cost of buying fewer engines.

This conclusion is also consistent when looking at the larger picture of future anticipated generation additions. While adding more GE-10s is attractive on the surface to retain the advantage of common spare parts and training, with the anticipated growth in generation this approach becomes uneconomic due to the higher per kW cost of engines and their poorer heat rate.

At the same time, proceeding with a 50 MW class engine as compared to the smaller engines offers significant advantages:

- Reduced cost per kW of generation
- Reduced heat rate, e.g., improved efficiency
- More effective use of space due to fewer units for the same plant power rating
- Better positioning for possible future plant growth since this is pragmatically the smallest size that makes sense for a future combined cycle plant and takes advantage of being able to add less than 50 MW to an existing plant without CEC review.

---

[3] "RPU Generation Projects Preliminary Engineering Study", Framatome ANP, March 31, 2003
[4] The capital costs developed by Framatome were exclusive of permitting, site prep, switchyard, and interconnection costs.

From the perspective of having multiple engines to maximize reliability, the single 50 MW class engine is still the right choice given the plans to add a second 50 MW engine at the same site in approximately three years. If the addition of a second engine were not in the long-term planning, then going with more GE-10s or a pair of 25 MW engines would have been more attractive.

CANDIDATE ENGINES

With the conclusion that a 50 MW class engine was the most cost effective approach, the next question is whether it makes sense to pre-select an engine model for the project considering the long-term generation strategy, available engines, and current market conditions. The major advantage of such an approach is to reduce the project schedule duration since a specific engine choice must be made to begin the air permitting process. By not pre-selecting an engine, there is a minimum four-month extension to the schedule since obtaining quotes and selecting the winning bidder must be done in series instead of being performed in parallel.

For a 50 MW peaker, five different options present themselves:

1. Alstom GTX-100 – a relatively new engine that is more akin to an industrial engine, best suited for combined cycle duty
2. General Electric LM6000 – an aero-derivative engine widely used in both peaking and combined cycle service
3. Pratt & Whitney FT8 TWINPAC – an aero-derivative engine that couples two 25 MW engines to a generator on a common shaft (the FT8 is the single engine version). The FT-8 TWINPAC is used for peaking and combined cycle applications (the combined cycle applications are mostly international).
4. Rolls Royce Trent – a relatively new engine that represents the latest technology in aero-derivatives (a generation later design than the LM6000 or FT-8)
5. Reciprocating Engines, e.g., Caterpillar, Cummins, Wartsila, others – spark ignited natural gas fueled engines that are combined in multiple for peaking or intermediate duty

The attached table summarizes some of the relevant parameters for these five options.

EVALUATION

In evaluating the engine choices, the following parameters were considered:

1. Net generation must be less than 50 MW to facilitate local permitting.
2. The Riverside average temperature is 63°F and ~1000' in elevation (average temperature and elevation are used to determine power for comparison to CEC 50 MW limit).
3. For the combustion turbines, actual performance at Riverside average conditions will be slightly poorer than the ISO ratings (60°F and sea level) due to higher temperature and elevation. Inlet air-cooling can be used in part to mitigate the performance drop off on hot days. While the performance of all engines suffers with increasing altitude or temperature, they do not derate at the same rate.
4. Water from the wastewater treatment plant is readily available. The availability of water at the alternate Jurupa site is most likely not an issue. Demineralized water will be required at a minimum for operation of the SCR[5].
5. In general, a water injected combustion turbine is preferable to a dry low NOx (DLE) engine due to greater combustion stability and less sensitivity to ramping load. A DLE engine also typically has a higher capital cost than its water injected stablemate. While using a DLE engine does avoid the need for demineralized water for injection, given that an SCR – which does require demineralized water - is required in any case for emissions mitigation, this is not really an advantage.
6. Reciprocating engines are impacted far less than combustion turbines by elevation and temperature and can be more efficient than simple cycle (peaking) combustion turbines in this size range.
7. For peaking duty, heat rate can be less important than $/kW due to limited hours (1,500 to 2,000 for Riverside). Heat rate becomes more important as operating hours increase or if future base load operation is a consideration.
8. In general recip O&M is greater than combustion turbines – though peaking duty takes its toll on both.

Based on above criteria and RPU's short-term and long-term plans, each engine was evaluated as follows (they are listed in alphabetical order):

[5] An SCR – Selective Catalytic Reduction – is used to reduce the combustion turbine exhaust emissions.

Riverside Public Utilites
50 MW Peaker Plant Engine Evaluation
May 19, 2003

1. Alstom GTX-100 – the GTX-100, at less than 50 MW, supports the project approach of permitting the plant locally. This engine is best suited to a combined cycle application – an opportunity that may not arise for seven years at best. Other engines being considered offer a better heat rate in peaking service and can also be effectively utilized in combined cycle later. If RPU were proceeding with a combined cycle plant of greater than 50 MW now, than this engine would have been worthy of consideration. However this not being the case, the GTX-100 is not a preferred engine for RPU's application.
2. General Electric LM6000 – the LM6000, at less than 50 MW, supports a local permitting strategy. This engine is widely used in both peaking and combined cycle service by several California municipal utilities and Independent Power Producers (IPP). As a consequence, it is very familiar to California permitting agencies, vendors of auxiliary equipment, and constructors. The LM6000 is available in both a water- injected (SPRINT) and dry low NOx version. Since water is readily available, the SPRINT would be the better choice to maximize generation. There are many "new and in the box" LM6000s available in the marketplace that have served to depress the current price of an LM6000 as compared to several years ago. Based on the foregoing, the LM6000 is a candidate for RPU's application.
3. Pratt & Whitney FT8 TWINPAC – the FT8 TWINPAC, like the LM6000, supports a local permitting approach since it would be less than 50 MW. CalPeak, an IPP, uses this engine in peaking service in California. This engine too, like the LM6000 and the Trent, is available as a water-injected engine and could be later used as the basis of a combined cycle plant. An advantage of the FT8 TWINPAC over the LM6000 is that it offers a higher power output. Based on the foregoing, the FT8 TWINPAC is also a candidate for RPU's application.
4. Rolls Royce Trent – The Trent is the latest technology engine and offers the best heat rate. Because of its being new in the marketplace, there are a limited number of engines in service in North America. The Trent's size in the water-injected configuration exceeds 50 MW and thus removes it from consideration since it cannot be locally permitted. The dry low NOx version of the engine could be rated at just less than 50 MW net, however a water-injected engine is preferable. If water were a constraint, this engine would warrant further consideration. Similarly, if RPU were proceeding with a plant of greater than 50 MW now, then this engine would have been worthy of consideration, particularly with its greater efficiency. Based on these considerations, the Trent is not a preferred option.

5. Reciprocating Engines, e.g., Caterpillar, Cummins, Wartsila, others – Reciprocating engines in multiple can be packaged to be less than 50 MW and thus this option would support local permitting. In addition there are several peaking plants that have been built using this approach both in California and elsewhere. However this option does not offer a good avenue to future conversion to base load generation. Therefore using reciprocating engines is not a preferred option.

CONCLUSION

From the preceding section there are two viable candidates for RPU – the LM6000 and the FT8 TWINPAC. Between the two, the LM6000 offers several advantages:

- The LM6000 is a more efficient engine than the FT8 TWINPAC, albeit slightly lower output, resulting in annual fuel savings of $221,000 based on 2,000 hours per year of operation at 48 MW and $5 per MMBtu natural gas. As the price of gas escalates, as current forecasts portend, this advantage becomes more important. This difference would also become greater as operating hours increase as part of anticipated base load operation.
- There is significantly more experience with other nearby municipal utilities in California and in the rest of the State with permitting and operating the LM6000.
- The LM6000 packages 50 MW in a single engine versus having to maintain two engines for essentially the same amount of power.
- There is a potential cost advantage for the LM6000 due to new but previously owned engines being readily available in the marketplace. These are engines that were ordered by developers and then canceled or delivered but not installed due to their intended project being cancelled. A similar excess of supply for FT8 TWINPACs does not exist.

Selecting an engine now offers significant schedule advantages by allowing work on air permitting to begin now rather than waiting a minimum of 4-5 months to request bids, obtain approval, and then begin work on the air permit. In addition, many other aspects of the plant permitting and design can also proceed.

While there is the possibility that in the current market an offer for an FT8 TWINPAC might be obtained that is lower than an LM6000, we believe that the same market conditions that would drive a low bid for the FT8 TWINPAC also exist for the LM-6000 – and are reinforced in the case of the LM6000 by the availability of excess engines. In light of this, we do not believe there is sufficient cause to take on the schedule delay associated with bidding different engine models[6]. To leverage this condition, bids should be solicited from these owners and brokers in addition to General Electric. Consideration of the available warranty will need to be a factor in arriving at the total evaluated cost.

In the end we believe the schedule advantage overrides the possibility of a lower FT8 TWINPAC bid and that the project should proceed based on an LM6000 and obtaining bids from General Electric and the secondary market.

[6] If an LM6000 bid was to be obtained only from General Electric and not include the secondary market, then we would recommend obtaining bids for both the LM6000 and the FT8 TWINPAC to overcome General Electric's market power.

OVERALL COMPARISON OF CANDIDATE ENGINES

Parameter	Alstom GTX-100	General Electric LM6000	Pratt & Whitney FT8 TWINPAC	Rolls Royce Trent	Various Recips
Power, kW	43,000	42,400 (DLE) 48,060 (SPRINT)	51,350	51,190 (DLE) 58,000 (WLE)	~50,000 (multiple units)
Heat Rate, Btu/kWh	9,215	8,200 (DLE) 8,430 (SPRINT)	8,890	8,210 (DLE) 8,528 (WLE)	Around 8,200
Efficiency	37%	41.6% (DLE) 40.5% (SPRINT)	38.4%	41.6% (DLE) 40.0% (WLE)	Around 43%
Water Injected Engine <50 MW Net	Yes	Yes	Yes	No	Yes
California Applications	City of Redding City of Vernon	Calpine Modesto Irrigation District Silicon Valley Power SMUD Others	CalPeak	None	Chowchilla Red Bluff

Values at ISO conditions of 60°F and sea level, RPU conditions are 63°F and 1,000'.

Net power from a plant would be less than the values shown due to auxiliary loads

Abbreviations:

DLE – Dry Low Emissions

WLE – Wet Low Emissions

SPRINT – Spray Intercooling

Acorn Generation Project
Owner's Engineer Project Meeting Minutes
June 24, 2003

Please note: The notes are presented in the order of the agenda. We actually started with the GA and ended with the discussion on additional plant configuration options to be studied. Thus some items seem out of order.

POWER's Project Status

- ✓ Project Overview – POWER is almost through the Kickoff phase of defining the project. The only item remaining is the Project Risk/Benefit Evaluation that was discussed later in the meeting and will be issued later this week. The conceptual design phase has begun.
- ✓ Budget Status – We are OK on budget with changes in scope resulting in some tasks deleted, completed earlier, or being added. As a result we are slightly over budget for the Kickoff tasks, under budget on the Site Selection and Project Delivery tasks.
  - o Deleted scope – Task 2 Site Suitability and Site Selection, Task 4 Select Project Strategy (addressed as part of Task 1)
  - o Added scope – Task 1 Engine Evaluation, Project Description, and Project Risk/Benefit Evaluation, 3x1

  POWER described the Work Scope Variances (WSV) they write for changes in scope. The changes have not been an issue so far. POWER will submit the past and future WSVs to Joe. RPU will pay $48K of our initial invoices based on initially approved funding and the balance after the $240K task order is funded.
- ✓ Current Schedule – reviewed the updated schedule, need to update completion schedule for the short circuit study. We'll have face-to-face monthly project review meetings the 2nd Wednesday of the month at the Orange Street conference room. We'll have project review conference calls the 4th Wednesday of the month. POWER will setup the calls.

Review of Past Deliverables

- ✓ Engine Evaluation – Bob is developing an approval document for Steve Blagdett. This will also need to be revised to incorporate RPU's Resource Planning report. POWER is proceeding based on an LM6000 Sprint.
- ✓ Project Delivery – EPC for power plant/switchyard, DBB for transmission line – no comments.
- ✓ Cost Estimate - ~$50 million with 15% contingency, this will need to be updated to include the fuel oil system.
- ✓ Cash Flow – no comments.
- ✓ Project Description – no comments.

Discussion Items

- ✓ Air permitting update – SCAQMD will issue a decision supporting segregation of the Acorn project and the WWTP recips. Karl had an update that we'll post to the PWC.

- ✓ WWTP Site Selection – based on the air permitting outlook, this will be the site and it will be leased from the WWTP.
- ✓ Project Risk Assessment/Cost Benefit – discussed the spreadsheet that had been prepared. General agreement it was conservative and resulted in the Acorn project being a better option than purchasing power. POWER needs to issue the report this week.
- ✓ SoCalGas Interconnect Status – no comments.
- ✓ RFIs - Status
  - RFI 1 – Open, awaiting recip plant data
  - RFI 2 – Open, awaiting WWTP data
  - RFI 3 – Closed, POWER has posted a preferred vendor list to the PWC
- ✓ Storm Water Pollution Prevention Plan and waste water discharge requirements – POWER is to develop the SWPPP. Bob Gill will look into water discharge requirements.
- ✓ CBO, Fire Marshall, Other Reviewers Involvement – Joe Carrasco will initiate contact the CBO. For the Fire Marshall, Joe will provide the plan that was developed for the Springs project. POWER will then interface with Fire Marshall directly
- ✓ Efforts to obtain Public Works land – in progress by Bob Gill, no action for POWER.
- ✓ Efforts to obtain City Planning approvals, generation and t-line – in progress by Bob Gill, no action for POWER.

Conceptual Design

- ✓ Status – The conceptual design phase has begun with initial GA completed, the Basis of Design outlined, and basic system definition. Design is proceeding based on an LM6000 at the Waste Water Treatment Plant (WWTP).
- ✓ Basis of Design – add a section for the fuel oil system, have a separate section for CEMS, are the Snow Loads and Freeze Protection sections required? Reviewed the deliverable list. RPU wants the EPC engineer to spec the PDC. POWER needs to evaluate whether to go with an evap cooler or a chiller based on RPU conditions.
- ✓ General Arrangement – reviewed the initial GA with several comments resulting:
  1. The 69/230 kV substation will have a difficult time fitting in. After a lot of discussion, the basic decision was that this is the last existing site for generation and it should be dedicated to that purpose. The substation will go the alternate site at Jurupa.
  2. Based on the proceeding, and RPU needing 50 MW of peaking in 2005, another 50 MW of peaking in 2008, and 120 MW of base/intermediate in 2012, develop the GA showing the maximum generation potential (assume all LM6000s for now). The most practical way to do this is to layout the engines on an east-west axis.
  3. Add a fuel oil tank for a fuel oil system. In the event of an earthquake and the gas pressure decays, RPU wants to be able to run on distillate in an emergency. Plan on running between 100-200 hours for permitting and sizing.
  4. Add access off of Payton at the southeast corner

5. There needs to be a security barrier that surrounds the plant and separates it from the WWTP. It may not need to be an architectural brick wall the entire length. POWER needs to develop a cost estimate for the complete wall so we understand how much it will cost. RPU just spent $750,000 for a 2 acre site ¼ the size of the WWTP site.
6. Move the 69 kV switchyard to the south end of the site
7. Reorient the engines so that they have an east-west axis with the stacks to the west
8. Want the GA to show the initial unit in black with the complete build out in gray

- ✓ Review Drawing Legend sheets – use the same legends as the Springs project
- ✓ P&IDs – review list of systems – add fuel oil system
- ✓ Electrical drawings – the list looks fine, the typical drawings will be needed.
- ✓ Controls & Communication – Bob Webb should start with Joe Carrasco. Joe will involve Dave Napp of RPU too. Remember to include a phone line for the CEMS DAS, this was forgotten and as a last minute item at Colton.
- ✓ Drawing Distribution – distribute to Bob, Joe, Dan, Dick, and Norm, we can add others later if needed
- ✓ Drawing Review Cycle – how long does RPU want to review the drawings – *2 weeks*
- ✓ Bidder Lists – NEW ITEM – POWER is maintaining lists of interested bidders, one for equipment and for EPC bidders. These will be posted weekly on the PWC.
- ✓ Site Survey, Geotech, and Visual Simulation – NEW ITEM – POWER is to develop a visual simulation for the 69 kV transmission line and the power plant from the Payton Road entrance. Lyle Hill of RPU will take pictures. POWER also needs to arrange for a site survey and geotech for the site. This will probably occur in July once the generation folk have control of the site. Joe will provide the names of any local firms RPU uses.
- ✓ Additional Plant Configurations – NEW ITEM – based on the benefit of the 50 MW plant, RPU wants to explore a bigger plant (up to 150-200 MW) that will cover their intermediate duty loads of 8 AM to 10 PM, five days a week (3,640 hours). Discussed expansion to a 1x1 or 2x1 combined cycle now. Given the nightly cycling of the plant, the complication of cycling a steam plant, and that since we would now be over 50 MW and CEC permitting would be required, another option that was discussed was to consider larger aeroderivatives (>50 MW) and go with a simple cycle plant. As a result, POWER will evaluate the following options:
    1. 1x1 LM6000 with a steam turbine sized for two CTs
    2. 2x1 LM6000
    3. 2x0 Trent
    4. 2x0 FT8TwinPak Plus

The initial step will be to look at heat rates and outputs (based on 100F) and see how different they are. For the options that look promising, then we'll develop a cost estimate(s). This information is needed quickly by RPU to finalize the plant configuration before getting project approval.

Closure

- ✓ POWER's Follow-on Scope – NEW ITEM – POWER should submit a proposal for the follow on scope. RPU wants to get this in place in July.
- ✓ Power's Performance +/Δ – POWER's done a great job and been responsive.
- ✓ Meeting +/Δ – meeting went well, accomplished a lot
- ✓ Next meeting? – July 9th at RPU's offices

Post-Meeting – Conference Call with Norm Stout & Dick Fine to obtain their comments on review of POWER's work products to date – This didn't take place.

ACTION ITEMS (all items for POWER unless otherwise noted)

1. *Provide WSVs to Joe Carrasco*
2. *Update schedule on short circuit study*
3. *Update Engine Evaluation report when Resource Planning report is complete*
4. *Update cost estimate to add fuel oil system*
5. *Post air permitting update to PWC*
6. *Issue Project Risk/Benefit Evaluation*
7. *Prepare SWPPP*
8. *Identify water discharge requirements – Bob Gill*
9. *Contact CBO – Joe Carrasco*
10. *Provide Springs Fire Plan – Joe Carrasco*
11. *Update Basis of Design*
12. *Revise GA as noted earlier*
13. *Prepare Visual simulation for the power plant*
14. *Prepare Visual simulation for the transmission line*
15. *Provide local survey and geotech names – Joe Carrasco*
16. *Obtain site survey and geotech*
17. *Develop a comparison for the following four configurations based on heat rate and output at 100F, and 14x5x52 service:*
    - ❑ *1x1 LM6000 with a steam turbine sized for two LM6000s*
    - ❑ *2x1 LM6000*
    - ❑ *2x0 Trent*
    - ❑ *2x0 FT8 TwinPak Plus*

    For those that are most promising, after consultation with RPU, develop cost estimates. Hold off on GA revision for a few days until we see where this is going to lead. This is a new scope item, submit a WSV.

POWER's Project Status

- ✓ Project Overview – POWER is proceeding with those aspects of the conceptual design that are not dependent on the final configuration. Once the plant configuration is finalized, we will resume work on the GA and all aspects of the conceptual design.
- ✓ Budget Status – The Kickoff task has been expanding to include new tasks associated with defining the project and plant configuration. As a result, the task is running over budget due to the added tasks and performing part of Task 4 as a part of this Task. Considering Tasks 1 and 4 together, we are OK on budget for the original scope. Approximately ten new tasks have been added to the project. The Work Scope Variances (WSV) and budgets for these tasks are being prepared and will be forwarded to RPU. This has also impacted the Project Management task, which is being expended faster than planned.
- ✓ Current Schedule – the conceptual design was scheduled for completion by the end of July. This completion date is slipping until the plant configuration is finalized.

Review of Past Deliverables

- ✓ Project Risk Assessment/Cost Benefit – No comments
- ✓ Plant Configuration – We had an extensive discussion o n the plant configuration. RPU will make a final decision in the next two months. In the meantime, POWER will resume the conceptual design based on the original plan of a 1x0 MW LM6000 peaker. POWER needs to look into whether the CEC differentiates between an expansion (add a steam turbine to convert to combined cycle) and adding another combustion turbine with either adding less than 50 MW.

Discussion Items

- ✓ Review 6/24 meeting minute action items
  1. Provide WSVs to Joe Carrasco – in progress
  2. Update schedule on short circuit study – in progress based on 10, 0 MW of generation, scheduled for 7/18 completion
  3. Update Engine Evaluation report when Resource Planning report is complete – this will be done when the Resource Planning report is available
  4. Update cost estimate to add fuel oil system – waiting for final plant configuration
  5. Post air permitting update to PWC - complete
  6. Issue Project Risk/Benefit Evaluation - complete
  7. Prepare SWPPP – WSV and budget in preparation for RPU review
  8. Identify water discharge requirements – Bob Gill has the information, Dave needs to get it from Bob
  9. Contact CBO – per Joe's e-mail this is no longer a concern
  10. Provide Springs Fire Plan – Joe Carrasco, in progress
  11. Update Basis of Design – we'll restart this based on a 1x0 LM6000
  12. Revise GA as noted earlier – we'll restart this based on a 1x0 LM6000

13. Prepare Visual simulation for the power plant – will be prepared after GA is OK'd
14. Prepare Visual simulation for the transmission line – photos being shot, simulation will then be prepared
15. Provide local survey and geotech names – Canceled since RPU will now self-perform the survey and geotech
16. Obtain site survey and geotech – RPU will do this, POWER as provided recommendations for both
17. Develop a comparison of alternate plant configurations - complete

- ✓ Air permitting update – no change from last time
- ✓ SoCal Gas Interconnect Status – have not heard back from SoCal Gas. Power will contact them again to get a schedule on when they expect to start.
- ✓ RFIs – Status
    - RFI 1 – We've received a drawing package for the recip plant and are reviewing it
    - RFI 2 – Open, awaiting WWTP data
    - RFI 3 – Closed, POWER has posted a preferred vendor list to the PWC
- ✓ Survey & Geotech – POWER provided a letter containing guidance on what information is required. The basic survey will be performed as part of the land transfer, with the remaining information to follow. We established the end of August as the goal to have all the information.
- ✓ Visual Simulation – WSVs and budgets in preparation. Jay will re-shoot the photos today for the transmission line routing with Lyle.
- ✓ Transmission Line DBB – discussed what role RPU wanted POWER to take on as Owner's Engineer for the transmission line Design-Bid-Build. RPU will decide whether they want to do the design themselves, issue a new RFP, look at an existing proposal, or other options.
- ✓ PDC Procurement – the duration to procure a PDC is about 20 weeks.

Conceptual Design

- ✓ Status – discussed earlier.
- ✓ GA – We'll proceed to revise the GA as discussed last meeting and today. This is needed by next Tuesday. Those comments are:
    1. Move the 69 kV switchyard to the south end of the site
    2. Layout a 3x1 LM6000 based combined cycle plant. Show the initial 1x0 in black and the balance of the 3x1 in gray.
    3. Reorient the engines so that they have an east-west axis with the stacks to the west
    4. Add access off of Payton at the southeast corner. This will be the main entrance to the plant.
    5. Provide more clear space on the west side of the plant between the plant and the Waste Water Treatment Plant.

6. Add a fuel oil tank for a fuel oil system. The system should be sized for 100-200 hours of operation.
7. There needs to be a security barrier that surrounds the plant and separates it from the WWTP. It may not need to be an architectural brick wall the entire length.

✓ Gas Turbine/SCR Spec – this is in progress.

Closure

✓ Power's Performance +/Δ – no deltas were identified, good job and responsive.
✓ Meeting +/Δ – no comments
✓ Next meeting – July 23rd at 9:00 AM Pacific via teleconference, POWER to set up AT&T conference call. August 13 at 8:00 AM at RPU's Orange street offices.

ACTION ITEMS (all items for POWER unless otherwise noted)

1. Update project schedule based on this meeting.
2. Provide WSVs to Joe Carrasco
3. Find out whether the CEC differentiates between expansion and addition
4. Update Engine Evaluation report when Resource Planning report is complete
5. Obtain water discharge requirements from Bob Gill
6. Provide Springs Fire Plan – Joe Carrasco
7. Obtain schedule from SoCal Gas
8. Transmission Line design approach – Lyle Hill
9. Revise GA as noted earlier – needed by Tuesday
10. Resume conceptual design based on 1x0 LM6000

Acorn Generation Project
Owner's Engineer Project Meeting
July 23, 2003

POWER's Project Status

- ✓ Project Overview – Proceeding with the conceptual design for the 1x0 LM6000 plant. The GA has been issued for review. The Gas Turbine/SCR spec, Basis of Design, P&IDs, Single Line are all underway. The Short circuit study is nearly complete.
- ✓ Budget Status & Work Scope Variances – Project Management is over-budget due to scope adds, project extension, and handling the various issues that have come up. Task 1, Kickoff is over-budget, however some of the Task 4 scope was addressed as part of the Task 1 scope so overall Task 1 and 4 are OK. Work Scope Variances have been issued for major scope additions.
- ✓ Current Schedule – plan on having conceptual design ready for review in mid-August.

Discussion Items

- ✓ Review 7/9 meeting minute action items
- ✓ RFIs – In good shape
- ✓ 2x0 Decision/Strategy – At a minimum RPU needs to have 50 MW by May '05. Power is to setup a meeting with the CEC for August 5, 6, 7, or 8. Steve Badgett, Bob Gill, and Joe Carrasco from RPU will participate. Intent of the meeting of the meeting is to discuss with the CEC RPU's plans, describe the site and interconnections and minimal complications, what process the CEC would apply to a RPU 2x0, explore whether CEC will use RPU's CEQA efforts as a starting point if the project grows.
- ✓ Visual Simulation – Discussed several options including 1) a schematic view from across the river looking at the plant including major wastewater treatment plant elements, and 2) a detailed view of the plant from the Payton side. Separate phone call to follow with Bob Gill and Joe Carrasco to finalize.

Conceptual Design

- ✓ GA – concern about which way the wind really blows and whether we should have the stacks on the east side. Bob will get some real data and we can re-orient the site if needed.
- ✓ Gas-Turbine/SCR Spec – there were some concerns about combining the turbine generator and SCR into one package. There will be a conference call at 0900 Thursday to discuss this.

Closure

- ✓ Next meeting – August 13 at RPU's Orange Street Conference Room at 8:00 AM

Acorn Generation Project
Owner's Engineer Project Meeting Minutes
August 27, 2003

POWER's Project Status

- ✓ Budget Status – POWER's conversion to ORACLE is complete. The original project budget was $240,000. With the approved Work Scope Variances, the budget is increased to $288,290. Through 8/26 expenditures are $228,739. Work Scope Variances 1-8 are approved. WSV #9 for Asset Management Software is on hold until after engine selection is made. POWER is submitting WSV #10 for CEC meeting support, #11 for borehole map, and #12 for the 1x0/2x0/2x1 Cost Estimate study.
- ✓ Current Status (see attached)

Discussion Items

- ✓ GA Revisions– discussed reorientation of the site to accommodate placing the stacks on east (downwind side). Also modified the site plan in anticipation of two simple cycle engines followed by combined cycle later on. Also modified the south end of the site to minimize grading and accommodate the existing topography and entrance from Payton. The GA will be posted later today. If needed, we should have a conference call next week to discuss comments.
- ✓ We also discussed the gas compressor location and noise concerns. The approach in the bid spec is to tell the vendor the location of the compressors relative to the site boundary and the site boundary noise limit (65 dB). If the gas compressor alone will cause the site limit to be exceeded, then the vendor must supply an enclosure. Enclosures introduce their own complications, particularly with respect to fire protection. Dick Fine offered that on another project he had seen 20' high removable steel panels used to funnel the noise upward and protect the site boundary. We discussed the combination of compressor and the engine noise and agreed that eventually we'll need to do a noise model to determine if any mitigation will be required.
- ✓ Level site versus stepped – due to the existing site topography, we are proposing that the plant be built on two levels to minimize earthmoving. Units 1 and 2 could be built on one level and the steam plant and other units be built on a lower level that better matches the northeast road connection to the Wastewater Treatment Plant.
- ✓ Sempra Interconnect – Sempra's position is that the plant should connect to the distribution system unless there is a compelling reason to connect to the transmission system. They are awaiting a compelling argument from their last visit to the site.
- ✓ Wastewater interfaces – Bob Gill has the action to get POWER a contact for the Wastewater Treatment Plant Interfaces
- ✓ Spec evaluation factors – POWER distributed some sample calcs for determining the evaluation factors that are going into the specs. POWER needs RPU concurrence on the assumptions of fuel cost, price of electricity, etc.
- ✓ September 10 Design Review – the next meeting will have a short meeting up front to go over Project Status followed by spending the rest of the day reviewing the conceptual design and specs.
- ✓ September 11 CalPeak FT8 TwinPak visit – Pratt & Whitney will be taking us on a tour in Escondido of the CalPeak Operations Center and warehouse followed by a tour of the

adjacent CalPeak FT8 TwinPak peaker. POWER will send out some info on the FT8 TwinPak so people can review it in advance of the meeting.

Closure

- ✓ Need to get meeting agendas out earlier
- ✓ Next meeting – September 10 at 8:00 AM. This will be an all-day design review. On the 11th, we'll be visiting the CalPeak FT8 TwinPak in Escondido.

Studies

- ✓ Engine Evaluation — Complete
- ✓ Project Delivery Evaluation — Complete
- ✓ 1x0 Detailed Cost Estimate — Complete
- ✓ Cash Flow — Complete
- ✓ Geotech Guidance — Complete
- ✓ Plant Configuration Study — Complete
- ✓ Risk Assessment — Complete
- ✓ CEC Permit Assessment/Meeting — Complete
- ✓ 1x0 vs. 2x0 Cost Estimate — Complete

Conceptual Design

- ✓ Drawing Coversheet — Complete
- ❑ General Arrangement — F/C 8/27, revised GA to flip engines and better fit survey
- ❑ Borehole Plan — F/C 8/28, revise based on final GA
- ❑ Design Criteria — F/C 9/3, final review starting 8/27
- ✓ P&IDs — Complete
- ✓ Control System Architecture — Complete
- ✓ Electrical Single Lines — Complete
- ✓ Short Circuit Study — Complete
- ❑ Combustion Turbine Spec — F/C 8/28, final review complete, incorporating comments
- ❑ SCR Spec — F/C 9/3, issue for internal review 8/28-29
- ❑ Gas Compressor Spec — F/C 8/29, final review complete, incorporating comments
- ❑ GSU Spec — F/C 9/2, internal comments submitted
- ❑ Water Balance — F/C 9/5

Visual Simulations

- ❑ Power Plant Simulation — F/C 9/3
  - View from Jurupa, update for final GA
  - View from across river, update for final GA
  - Bird's eye view, update for final GA
  - View from Wastewater, get picture and create
- ❑ Transmission Line Simulation — F/C 8/27 with poles and under build
  F/C 9/3 with comments and conductors
  - Seven steel pole views
  - Seven wood pole views

Acorn Generation Project
Owner's Engineer Project Meeting Minutes
September 10, 2003

POWER's Project Status

- ✓ Budget Status – Power's expenditures at $270K. Submitting Supplemental Agreement with the scope changes
- ✓ Schedule - reviewed the schedule in some detail. It's OK to notify successful equipment bidders while the RPU approval process of the bid evaluation proceeds.
- ✓ PWC Usage – RPU gets two types of notification emails. One has a click here and goes directly t the PWC folder. The other has a long URL that takes them to the login page which then takes them to a page that does't work i.e., "page is not available." It seems that Karol's e-mails are one way and other's are a different way (not clear which is which way). We need to resolve this.

Discussion Items

- ✓ Transmission Line Update – Dick Fine's comments were discussed. RPU will look at moving the one set of poles onto the railroad right-of-way. The parallel set of poles are SCE poles. RPU will have responses back on other T-line proposals by October 8. A decision on who will do the design will be made after that. Need to update the schedule to incorporate this sequence.
- ✓ Project Name – the project name is now Jurupa Energy Center. We need to change all documents to reflect that on their next revision.
- ✓ 1x0/2x0 Decision – We'll have a decision by the end of September.
- ✓ Dual Fuel – this decision will be affected b what Sempra tells us at the Friday meeting. If Springs and Jurupa are on separate gas transmission lines, then not having dual fuel may be acceptable. A decision will be made next week.
- ✓ Engines – if we don't go for a dual fuel plant, then we'll include the Trent in the bidding pool. If we go with dual fuel, the Trent will be excluded due to the 8 hours required for a burner change out.
- ✓ CTG/SCR Bidding- We decided to bid the CTG & SCR as a package. We will develop one integrated form for the vendors to use in submiting their package bid.

General Arrangement

Move BOP stuff – raw water/fire tank, firewater pumps, oil tank, demin system, gas compressors, steam turbine, and cooling tower to the north end. Add noise enclosures around each gas compressor. Add a redundant gas compressor.

Move warehouse next to Admin building, move first unit south if possible, ghost in as many units as possible beyond the 3x1 (4x1, 5x1)

Do not show cogen plant on the GA

Turn switchyard 90 degrees and use freed up space on the east end of the units, leave space for a third T-line

Add landscaping around the perimeter as shown in the GA

Bid Specs Common

Require the bidders to initial every page

Include a CD of the entire proposal

Give bidders access to the PWC to view their bid (if we can do this so they can't see the other bidders)

See specific spec mark-ups for additional changes

Design Criteria/EPC Spec

Front gate needs to have an intercom that pages the Admin Building and the whole site

Need to include landscaping requirements

Will need a separate drawing that shows cogen plant and crossties. Do not show cogen and Jurupa on the same GA drawing.

Admin Building

- Control Room
- Plant Manager's Office
- Office for two operators
- Document Room
- Break room
- Restrooms with locker space and a shower in each
- Office Equipment room (copy machine, printer, fax, etc.)
- Two extra offices for visiting people/contractors
- Computer/Communications Room
- Electrical Room
- Battery Room
- Training Room

The security system should include:

- Site perimeter microwave motion detectors
- Video capture system at the gate
- Surveillance cameras that can be viewed from the control room or from the Utility Operations Center across Riverside's network. Some of the cameras should be capable of remote operation from he control room or UOC.

The unit should be capable of isochronous operation while being operated either locally or remotely from the Utility Operations Center

Include requirement for a Power System Stabilizer

Provide water spigots, compressed air, 120V, and 480V connections around the site for maintenance/operations use. At Springs RPU is needing to string a lot of extension cords.

Additional comments will be forthcoming next week

Other Drawings

Additional comments will be forthcoming next week

Closure

- ✓ September 11 CalPeak FT8 TwinPak @10:00 AM and PurEnergy 2x1 LM6000 visit
- ✓ September 12 meeting @ 8:30 AM with RPU Procurement on specs
- ✓ September 12 meeting @ 10:00 AM with Sempra on gas interconnect
- ✓ Complete Design Review – next week
- ✓ Next meeting – September 24 Teleconference at 9:00 AM

Studies

✓ Engine Evaluation	Complete
✓ Project Delivery Evaluation	Complete
✓ 1x0 Detailed Cost Estimate	Complete
✓ Cash Flow	Complete
✓ Geotech Guidance	Complete
✓ Plant Configuration Study	Complete
✓ Risk Assessment	Complete
✓ CEC Permit Assessment/Meeting	Complete
✓ 1x0 vs. 2x0 Cost Estimate	Complete

Conceptual Design

✓ Drawing Coversheet	Update project title change from Acorn to Jurupa
✓ General Arrangement	Requires update, see comments and markup
✓ Borehole Plan	Borehole map requires update to reflect new GA
✓ Design Criteria	Requires update
✓ P&IDs	Review incomplete, add redundant gas compressor
✓ Control System Architecture	Complete
✓ Electrical Single Lines	Complete
✓ Short Circuit Study	Complete
✓ Combustion Turbine Spec	Update with comments
✓ SCR Spec	Update with comments
✓ Gas Compressor Spec	Update with comments
✓ GSU Spec	Update with comments
✓ Water Balance	Complete

Visual Simulations

✓ Power Plant Simulation	Complete – will need to update later with new GA
✓ Transmission Line Simulation	Complete

RESPONSE TO CURE DATA REQUESTS SET 1

REQUEST #1

Acorn Generation Project Plant Configuration Evaluation
1X1 LM6000

Acorn Generation Project
Plant Configuration Evaluation
1X1 LM6000

Parameter	Value	Annual Cost
Discount Rate (%)	4.40	
Net Output (Average kW)	64,828	
Hours per year of operation (hrs)	3,640	
Heat Rate (LHV) (Btu/kWh)	7,295	
Fuel Cost (HHV) ($/MMbtu)	$4.75	
HHV/LHV Ratio	1.1100	
Fuel Cost ($/year)		$9,076,238
Variable O&M ($/MWh)	$3.00	
Variable O&M ($/year)		$707,922
Fixed O&M ($/MW)	$20,000.00	
Fixed O&M ($/year)		$1,296,560
Total O&M ($/year)		$11,080,720

Year Power Plant 2003-2014	Total	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Capital Investment	$76,839,000												
O&M Cost	$156,475,153			$11,080,720	$10,613,717	$10,166,395	$9,737,926	$9,327,516	$8,934,402	$8,557,856	$8,197,180	$7,851,705	$7,520,791
Annual Costs		$0	$0	$11,080,720	$10,613,717	$10,166,395	$9,737,926	$9,327,516	$8,934,402	$8,557,856	$8,197,180	$7,851,705	$7,520,791
20 Year Lifetime Cost	$233,314,153												

Year Power Plant 2015-2025	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
O&M Cost	$7,203,822	$6,900,213	$6,609,399	$6,330,842	$6,064,025	$5,808,453	$5,563,653	$5,329,169	$5,104,568	$4,889,433	$4,683,365
Annual Costs	$7,203,822	$6,900,213	$6,609,399	$6,330,842	$6,064,025	$5,808,453	$5,563,653	$5,329,169	$5,104,568	$4,889,433	$4,683,365

Lifetime MWh Generated	4,719,478
Lifetime Cost	$233,314,153
Lifetime $/MWh	$49.44

Acorn Generation Project
Plant Configuration Evaluation
2X1 LM6000

Parameter	Value	Annual Cost
Discount Rate (%)	4.40	
Net Output (Average kW)	133,647	
Hours per year of operation (hrs)	3,640	
Heat Rate (LHV) (Btu/kWh)	7,094	
Fuel Cost (HHV) ($/MMbtu)	$4.75	
HHV/LHV Ratio	1.1100	
Fuel Cost ($/year)		$18,195,683
Variable O&M ($/MWh)	$3.00	
Variable O&M ($/year)		$1,459,425
Fixed O&M ($/MW)	$20,000.00	
Fixed O&M ($/year)		$2,672,940
Total O&M ($/year)		$22,328,049

Year Power Plant 2003-2014	Total	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Capital Investment	$101,839,000												
O&M Cost	$315,303,048			$22,328,049	$21,387,020	$20,485,651	$19,622,271	$18,795,279	$18,003,141	$17,244,388	$16,517,613	$15,821,468	$15,154,663
Annual Costs		$0	$0	$22,328,049	$21,387,020	$20,485,651	$19,622,271	$18,795,279	$18,003,141	$17,244,388	$16,517,613	$15,821,468	$15,154,663
20 Year Lifetime Cost	$417,142,048												

Year Power Plant 2015-2025			2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
O&M Cost			$14,515,961	$13,904,177	$13,318,177	$12,756,875	$12,219,229	$11,704,242	$11,210,960	$10,738,467	$10,285,888	$9,852,383	$9,437,149
Annual Costs			$14,515,961	$13,904,177	$13,318,177	$12,756,875	$12,219,229	$11,704,242	$11,210,960	$10,738,467	$10,285,888	$9,852,383	$9,437,149

Lifetime MWh Generated	9,729,502
Lifetime Cost	$417,142,048
Lifetime $/MWh	$42.87

Acorn Generation Project
Plant Configuration Evaluation
1X0 LM6000

Parameter	Value	Annual Cost
Discount Rate (%)	4.40	
Net Output (Average kW)	47,048	
Hours per year of operation (hrs)	3,640	
Heat Rate (LHV) (Btu/kWh)	8,884	
Fuel Cost (HHV) ($/MMbtu)	$4.75	
HHV/LHV Ratio	1.1100	
Fuel Cost ($/year)		$8,021,724
Variable O&M ($/MWh)	$3.00	
Variable O&M ($/year)		$513,764
Fixed O&M ($/MW)	$20,000.00	
Fixed O&M ($/year)		$940,960
Total O&M ($/year)		$9,476,448

Year Power Plant 2003-2014	Total	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Capital Investment	$35,226,000												
O&M Cost	$133,820,599			$9,476,448	$9,077,057	$8,694,499	$8,328,064	$7,977,073	$7,640,875	$7,318,845	$7,010,388	$6,714,931	$6,431,927
Annual Costs		$0	$0	$9,476,448	$9,077,057	$8,694,499	$8,328,064	$7,977,073	$7,640,875	$7,318,845	$7,010,388	$6,714,931	$6,431,927
20 Year Lifetime Cost	$169,046,599												

Year Power Plant 2015-2025			2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
O&M Cost			$6,160,849	$5,901,197	$5,652,487	$5,414,260	$5,186,073	$4,967,502	$4,758,144	$4,557,609	$4,365,526	$4,181,538	$4,005,305
Annual Costs			$6,160,849	$5,901,197	$5,652,487	$5,414,260	$5,186,073	$4,967,502	$4,758,144	$4,557,609	$4,365,526	$4,181,538	$4,005,305

Lifetime MWh Generated	3,425,094
Lifetime Cost	$169,046,599
Lifetime $/MWh	$49.36

Acorn Generation Project
Benefit Evaluation
2X0 LM6000

Parameter	Value	Annual Cost
Discount Rate (%)	4.40	
Net Output (Average kW)	94,159	
Hours per year of operation (hrs)	3,640	
Heat Rate (LHV) (Btu/kWh)	8,878	
Fuel Cost (HHV) ($/MMbtu)	$4.75	
HHV/LHV Ratio	1.1100	
Fuel Cost ($/year)		$16,043,346
Variable O&M ($/MWh)	$3.00	
Variable O&M ($/year)		$1,028,216
Fixed O&M ($/MW)	$20,000.00	
Fixed O&M ($/year)		$1,883,180
Total O&M ($/year)		$18,954,742

Year Power Plant 2003-2014	Total	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Capital Investment	$63,557,000												
O&M Cost	$267,667,279			$18,954,742	$18,155,883	$17,390,693	$16,657,752	$15,955,701	$15,283,239	$14,639,117	$14,022,143	$13,431,172	$12,865,107
Annual Costs		$0	$0	$18,954,742	$18,155,883	$17,390,693	$16,657,752	$15,955,701	$15,283,239	$14,639,117	$14,022,143	$13,431,172	$12,865,107
20 Year Lifetime Cost	$331,224,279												

Year Power Plant 2015-2025			2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
O&M Cost			$12,322,899	$11,803,543	$11,306,076	$10,829,575	$10,373,156	$9,935,973	$9,517,216	$9,116,107	$8,731,903	$8,363,892	$8,011,391
Annual Costs			$12,322,899	$11,803,543	$11,306,076	$10,829,575	$10,373,156	$9,935,973	$9,517,216	$9,116,107	$8,731,903	$8,363,892	$8,011,391

Lifetime MWh Generated	6,854,775
Lifetime Cost	$331,224,279
Lifetime $/MWh	$48.32

Acorn Generation Project
Plant Configuration Evaluation
3X0 LM6000

Parameter	Value	Annual Cost
Discount Rate (%)	4.40	
Net Output (Average kW)	141,272	
Hours per year of operation (hrs)	3,640	
Heat Rate (LHV) (Btu/kWh)	8,876	
Fuel Cost (HHV) ($/MMbtu)	$4.75	
HHV/LHV Ratio	1.1100	
Fuel Cost ($/year)		$24,065,304
Variable O&M ($/MWh)	$3.00	
Variable O&M ($/year)		$1,542,690
Fixed O&M ($/MW)	$20,000.00	
Fixed O&M ($/year)		$2,825,440
Total O&M ($/year)		$28,433,435

Year Power Plant 2003-2014	Total	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Capital Investment	$89,990,000												
O&M Cost	$401,519,575			$28,433,435	$27,235,091	$26,087,252	$24,987,789	$23,934,664	$22,925,923	$21,959,696	$21,034,192	$20,147,693	$19,298,557
Annual Costs		$0	$0	$28,433,435	$27,235,091	$26,087,252	$24,987,789	$23,934,664	$22,925,923	$21,959,696	$21,034,192	$20,147,693	$19,298,557
20 Year Lifetime Cost	$491,509,575												

Year Power Plant 2015-2025			2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
O&M Cost			$18,485,208	$17,706,138	$16,959,902	$16,245,117	$15,560,457	$14,904,652	$14,276,487	$13,674,796	$13,098,463	$12,546,421	$12,017,644
Annual Costs			$18,485,208	$17,706,138	$16,959,902	$16,245,117	$15,560,457	$14,904,652	$14,276,487	$13,674,796	$13,098,463	$12,546,421	$12,017,644

Lifetime MWh Generated	10,284,802
Lifetime Cost	$491,509,575
Lifetime $/MWh	$47.79

Acorn Generation Project
Plant Configuration Evaluation
2X0 FT8

Parameter	Value	Annual Cost
Discount Rate (%)	4.40	
Net Output (Average kW)	109,439	
Hours per year of operation (hrs)	3,640	
Heat Rate (LHV) (Btu/kWh)	9,715	
Fuel Cost (HHV) ($/MMbtu)	$4.75	
HHV/LHV Ratio	1.1100	
Fuel Cost ($/year)		$20,404,826
Variable O&M ($/MWh)	$3.00	
Variable O&M ($/year)		$1,195,074
Fixed O&M ($/MW)	$20,000.00	
Fixed O&M ($/year)		$2,188,780
Total O&M ($/year)		$23,788,680

Year Power Plant 2003-2014	Total	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Capital Investment	$69,165,000												
O&M Cost	$335,929,188			$23,788,680	$22,786,092	$21,825,758	$20,905,899	$20,024,807	$19,180,850	$18,372,462	$17,598,143	$16,856,459	$16,146,034
Annual Costs		$0	$0	$23,788,680	$22,786,092	$21,825,758	$20,905,899	$20,024,807	$19,180,850	$18,372,462	$17,598,143	$16,856,459	$16,146,034
20 Year Lifetime Cost	$405,094,188												

Year Power Plant 2015-2025			2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
O&M Cost			$15,465,549	$14,813,745	$14,189,411	$13,591,389	$13,018,572	$12,469,897	$11,944,346	$11,440,944	$10,958,759	$10,496,895	$10,054,497
Annual Costs			$15,465,549	$14,813,745	$14,189,411	$13,591,389	$13,018,572	$12,469,897	$11,944,346	$11,440,944	$10,958,759	$10,496,895	$10,054,497

Lifetime MWh Generated	7,967,159
Lifetime Cost	$405,094,188
Lifetime $/MWh	$50.85

Acorn Generation Project
Plant Configuration Evaluation
2X0 Trent

Parameter	Value	Annual Cost
Discount Rate (%)	4.40	
Net Output (Average kW)	112,912	
Hours per year of operation (hrs)	3,640	
Heat Rate (LHV) (Btu/kWh)	8,808	
Fuel Cost (HHV) ($/MMbtu)	$4.75	
HHV/LHV Ratio	1.1100	
Fuel Cost ($/year)		$19,086,899
Variable O&M ($/MWh)	$3.00	
Variable O&M ($/year)		$1,232,999
Fixed O&M ($/MW)	$20,000.00	
Fixed O&M ($/year)		$2,258,240
Total O&M ($/year)		$22,578,138

Year Power Plant 2003-2014	Total	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Capital Investment	$73,618,000												
O&M Cost	$318,834,660			$22,578,138	$21,626,569	$20,715,105	$19,842,054	$19,005,799	$18,204,788	$17,437,537	$16,702,621	$15,998,679	$15,324,406
Annual Costs		$0	$0	$22,578,138	$21,626,569	$20,715,105	$19,842,054	$19,005,799	$18,204,788	$17,437,537	$16,702,621	$15,998,679	$15,324,406
20 Year Lifetime Cost	$392,452,660												

Year Power Plant 2015-2025			2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
O&M Cost			$14,678,549	$14,059,913	$13,467,350	$12,899,760	$12,356,092	$11,835,337	$11,336,530	$10,858,745	$10,401,097	$9,962,737	$9,542,851
Annual Costs			$14,678,549	$14,059,913	$13,467,350	$12,899,760	$12,356,092	$11,835,337	$11,336,530	$10,858,745	$10,401,097	$9,962,737	$9,542,851

Lifetime MWh Generated	8,219,994
Lifetime Cost	$392,452,660
Lifetime $/MWh	$47.74

RESPONSE TO CURE DATA REQUESTS SET 1

REQUEST #3

RERC Project's Anticipated Operating Scenario

Approval of Generation Project – Riverside Energy Resource Center – Additional Appropriation

CITY OF RIVERSIDE

CITY COUNCIL MEMORANDUM

People Serving People

Riverside All-America City 1998

HONORABLE MAYOR AND CITY COUNCIL **DATE:** February 3, 2004

ITEM NO: 48

SUBJECT: **APPROVAL OF GENERATION PROJECT – RIVERSIDE ENERGY RESOURCE CENTER – ADDITIONAL APPROPRIATION**

BACKGROUND:

In December 2002 the Riverside Public Utilities (RPU) Power Resources Division prepared an update to the Long-Range Power Resource Plan. The plan called for additional base-load and peaking resources through 2013 to meet growing customer demand and replace long-term contracts that expire during that timeframe. Various alternatives exist for filling the ten-year power supply needs, and these alternatives were discussed during the presentation of the plan. One alternative that could serve a dual purpose in providing needed peaking power beginning in 2005, as well as additional system reliability in case of an emergency, is the installation of an additional 50 MW peaking plant within the City of Riverside (City) limits.

A number of studies and various analyses have been performed. These include construction costs; reliability enhancement; environmental obstacles including air quality; risk; and cost benefits. Staff believes that constructing a 50 MW generation plant with associated substation facilities located at the wastewater treatment facility on Acorn Street in the northwesterly area of the City, and connecting it with a 69 kV transmission line to the RPU grid, would best serve the City in meeting resource requirements. This project was previously discussed with Board and City Council in conjunction with the approval of the 2003-2008 Capital Improvement Program, and periodic updates were provided to the Board Electric Committee and City Council Land Use Committee.

To date, RPU staff has:

- Reviewed preliminary permitting, including environmental and air quality, for both generation and transmission.
- Developed requests for proposals, including contracts preparation for some of the major components and functions, including engineering.
- Proposed detail budget and cash flow development.
- Began public awareness efforts.
- Developed financing alternatives.
- Performed an analysis of building one versus two 50 MW units.

This work was approved by the Board of Public Utilities at its July 18, 2003, meeting.

Based on this preliminary work, staff has found no fatal flaws with this project and recommends proceeding to insure the generators will be online and available, and the transmission line constructed, for summer 2005 energy needs. Staff has completed its financial analysis that demonstrates constructing a second unit now to meet load expected for 2008 offers substantial project savings of almost $10 million. Other benefits to the City include increased system reliability and contingency coverage, and the ability to postpone substantial capital improvements for several years at the VISTA Substation. Due diligence during Phase 1 allows further refinement of the project budget. If one unit is built, the revised cost estimate is $49,000,000 including transmission facilities. The estimated work order for the project if two units are constructed is $75,000,000 including transmission facilities. A transmission line connecting the proposed plant and the Mt. View Substation will need to be constructed regardless of the number of units.

In conjunction with approval of the capital project itself, staff is also recommending approval of two new staff positions to operate the new plant. Staff is requesting the approval of two generation technician positions to complement the two positions hired to operate the Springs generation project (four 10 MW peaking units). The staff hired for this project would be involved in the engineering and planning phases of the project and perform inspection activities prior to commercial operation to obtain in depth training on the new plant. The goal is to fill the positions in July 2004. Both staff positions are required even if only one unit is approved.

It is also proposed that this project be financed with revenue bonds that will be paid back over the life of the generating plant (20 to 30 years). Use of revenue bonds for this type of project allocates the cost of the project to the customers who will be receiving the benefit of the power, versus having current customers pay up front for energy that will benefit future customers. The approval process for issuance of revenue bonds takes several months and will require a public hearing before the City Council. At this time, staff is requesting conceptual approval of using bond monies for this project and instructions to move forward with the forming of a financing team to issue revenue bonds.

The proposed construction of the 100 MW power plant and its associated transmission line will be licensed with the State of California's Energy Commission (CEC). The CEC will be the lead agency for all environmental permitting including the California Environmental Quality Act (CEQA) process. All public meetings for input and hearings will be held in the City of Riverside. The project team including staff members from the City's Planning, Public Works, Legal, and Property Services have been and will continue to work with the CEC throughout the project approval process.

The Board of Public Utilities, at its January 16, 2004, meeting recommended approval of this project.

Additionally, this item was presented to the City Council Land Use Committee, at its January 22, 2004, meeting. The Committee, with all members present, recommended approval.

FISCAL IMPACT:

At this time, the estimated project costs to build one unit, including transmission facilities and other appurtenances, is $49 million. The estimated costs to build two units now (versus waiting until 2008 to build a second unit) are $75.0 million, a gross savings of over $15 million. Deducting increased costs for plant operation and additional bond interest, building two units in 2005 is expected to save a net $9.5 million over the alternative to wait until 2008 for the second unit. Additional appropriation of $20 million is required to construct the second unit mentioned above.

Adding two additional generation technicians to the operating budget will cost approximately $187,000 per year, including salaries and benefits.

Additional debt service costs for the bond issue, along with other operating costs, are estimated to be $5.9 million annually. The majority of these costs are currently included in the power supply budget and electric rate structure since these plants are replacing power contracts already in place. A small rate increase of approximately 1.25% may be required in November 2005 to cover the increased power costs and use of some reserves to fund operation of the second plant three years earlier than planned. The current contracts expiring in 2005 (CDWR) were originally negotiated in 1996. The energy prices in these contracts are very low compared to current market prices for peaking power. This rate increase will be needed even if another alternative is used.

ALTERNATIVES:

As discussed, an alternative would be not to consider additional internal generation and rely solely on the market, using long-term contracts and standard block contracts, or daily market purchases. These alternatives are currently not recommended due to the goal to diversify the power resource portfolio with owned plants, counterparty contracts, different fuel sources, and have internal generation to improve system reliability in the event of transmission grid disruption.

RECOMMENDATIONS:

That the City Council:

1. Approve the construction of the Riverside Energy Resource Center consisting of two 50 MW units ***and associated transmission line subject to completion of the California Environmental Quality Act process by the California Energy Commission as the lead agency***;
2. Approve the additional appropriation of $20 million to capital project Riverside Energy Resource Center, account 510-6130000-470684 to provide for building the second 50 MW unit of this project; and
3. Approve the addition of two generation technician positions in new Electric Cost Center 510-612013 (Riverside Energy Resource Center Generation Project) effective June 1, 2004.

Prepared by:

Thomas P. Evans
Public Utilities Director

Approved by:

George A. Caravalho
City Manager

Approved as to form:

Gregory P. Priamos
City Attorney

Concurs with:

Paul C. Sundeen
Finance Director

Concurs with:

Chuck Beaty
Chair, Land Use Committee

TPE/SB:gsg
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Attachment: Board of Public Utilities Minutes – January 16, 2004

(13) APPROVAL OF GENERATION PROJECT – RIVERSIDE ENERGY RESOURCE CENTER – ADDITIONAL APPROPRIATION

Assistant Director Finance/Resources Donna Stevener updated the Board of the Riverside Energy Resource Center project with a PowerPoint presentation and stated that staff was asking for formal approval from the Board to move forward with the project. This project is for two 50 MW peaking plants with an estimated cost for both plants to be approximately $75 million that includes 1.2 mile transmission lines to connect to our system. This plant is at our Wastewater Treatment Facility on Acorn Street and the completion time is expected for May 2005. This plant will give many benefits including diversity to our power supply portfolio, emergency backup and reliability to our system and allows us to postpone major upgrades to the Vista Substation owned by Southern California Edison, the one point of entry into our city where all of our power comes from. Ms. Stevener expressed that building both plants at the same time would save RPU approximately $12 million and that there are no long-term contracts in the market available now, only 3-year contracts. Ms. Stevener and Assistant Director Energy Delivery Steve Badgett answered questions from the Board members.

The Board of Public Utilities:

(1) Approved and recommended that the City Council approve the additional appropriation of $20 million to capital project Riverside Energy Resource Center, account 510-6130000-470684 to provide for building the second 50 MW unit of this project;

(2) Approved the increase in estimated capital expenditure of $70,744,000 for Work Order 632954 (generation portion) and an increase of $1,756,000 for Work Order 637148 (associated transmission lines) to include funds needed for completion of Phase 2 of this project;

(3) Authorized staff to move forward with equipment procurement, award of bids, and all other activities associated with Phase 2 of this project;

(4) Approved and recommended that the City Council approve the addition of two generation technician positions in new Electric Cost Center 510-612013 (Riverside Energy Resource Center Generation Project) effective June 1, 2004; and

(5) Endorsed the concept of issuing revenue bonds to fund the capital portion of this project and instruct staff to begin the process of obtaining approvals to issue said bonds.

Motion – Newberry, Jr., P.E. Second – Gage.

Ayes: Acharya, Hubbard, Barnhart, Anderson, Newberry, Jr., P.E., Tavaglione, and Gage.

Noes: None

Abstain: None

Absent: Peter Hubbard

DIRECTOR'S REPORT

(A) Legislative Update – CMUA

(B) Open and Closed Work Orders – December 2003

(C) Draft Monthly Benchmark Report Cards – December 2003

(D) Water Highlights – December 2003

(E) Monthly Power Supply Report – November 2003

(F) Rolling Calendar Outlining Future Utility Projects as of January 9, 2004

SYSTEMATIC REPORTING ON CONFERENCES/SEMINARS

WORKSHOP

The Board of Public Utilities moved the meeting to the Art Pick Council Chamber Board Room to discuss the following items:

(14) 2004-2009 CAPITAL IMPROVEMENT PROGRAM APPROVAL

The Board of Public Utilities held a workshop to present the proposed 2004-2009 Capital Improvement Program for approval and potential rate impacts.

Motion – Gage. Second – Tavaglione.

Ayes: Acharya, Barnhart, Anderson, Newberry, Jr., P.E., Tavaglione, and Gage.

Noes: None

Abstain: None

Absent: Peter Hubbard

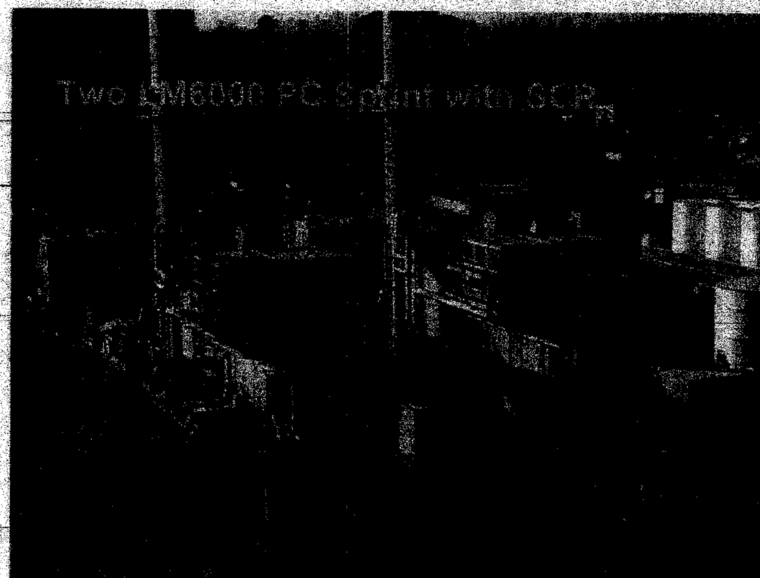
Board Member Conrad Newberry, Jr., P.E. left the meeting at 9:45 a.m.

CITY OF RIVERSIDE PUBLIC UTILITIES

Filling Power Resource Needs for 2005 and Beyond

Proposed Riverside Energy Resource Center (RERC)

48-6



City Council

February 3, 2004

CITY OF RIVERSIDE
PUBLIC UTILITIES

Riverside Energy Resource Center Project Highlights

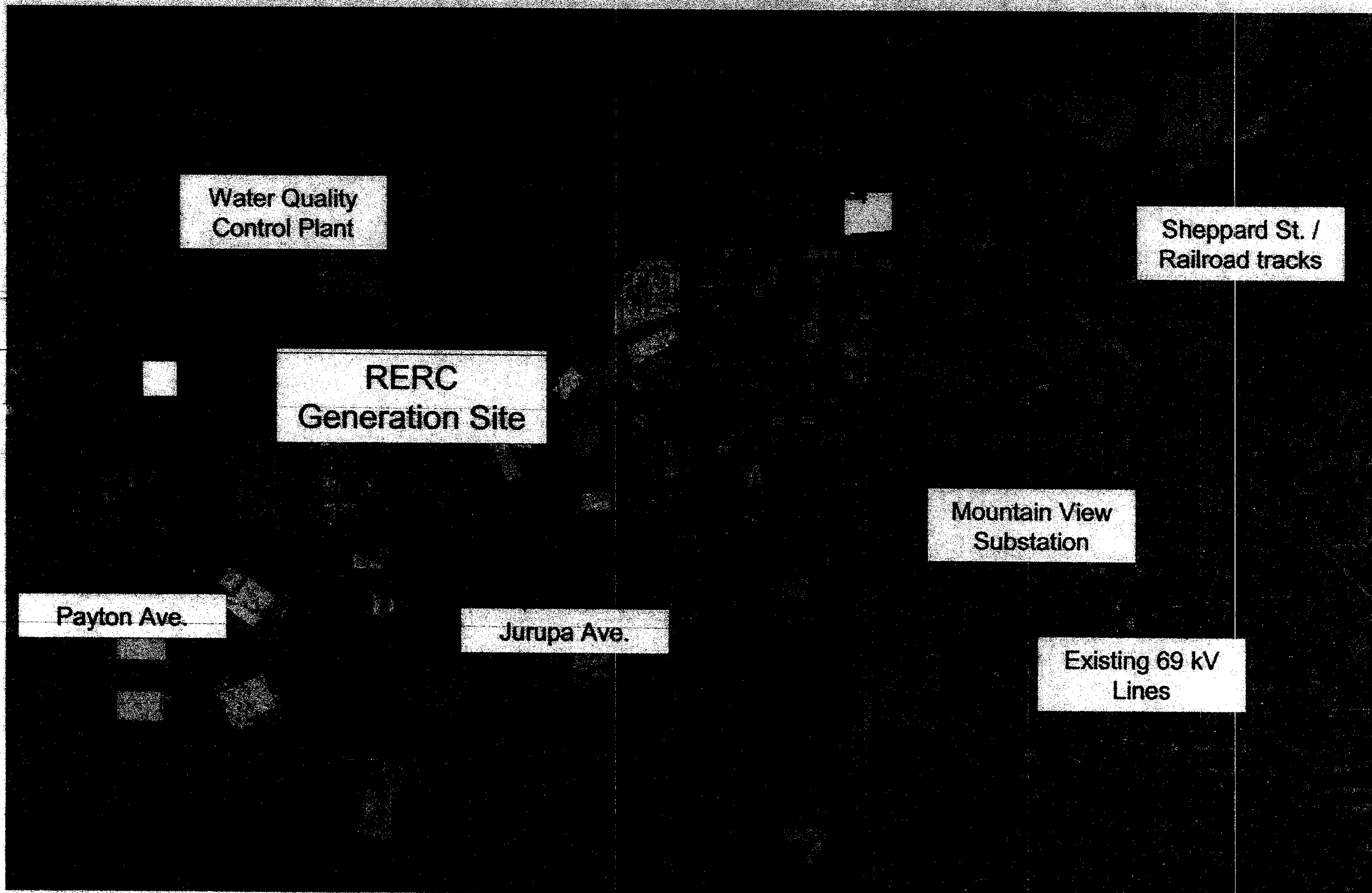
48-7

- Two 50 MW Power Plants (Peaking Units)
- Estimated cost - $75 million including related 1.2 mile transmission line
- Site: Acorn Street, next to Sewer Plant
- Expected completion date: May 2005
- Benefits: Diversify power sources, emergency back-up and postpone VISTA (Edison) upgrades
- Expected Average Plant cost - 7.5 cents/kWh
- Current wholesale peaking option rates 7.4 – 8.0 cents/kWh

CITY OF RIVERSIDE PUBLIC UTILITIES

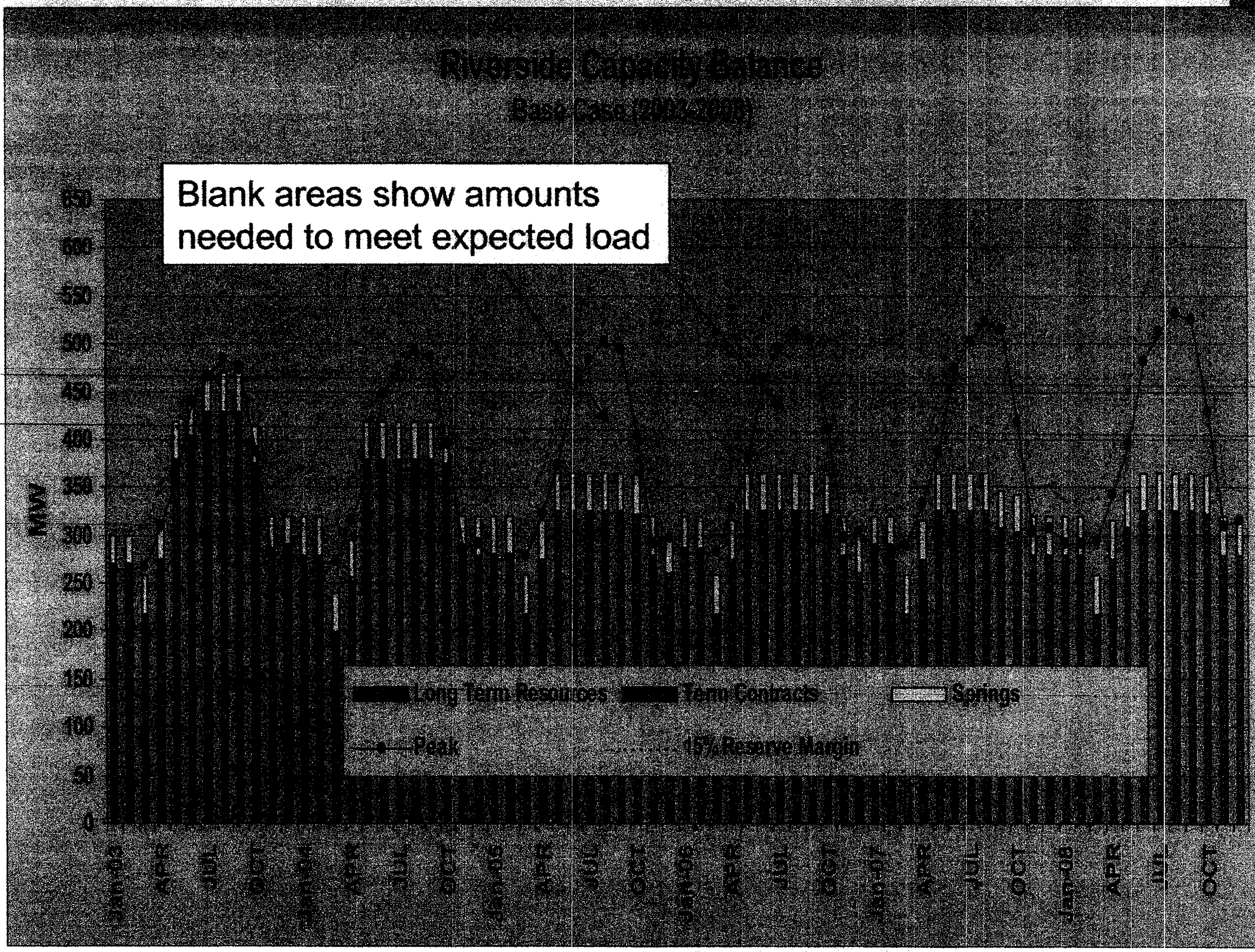
Proposed Riverside Energy Resource Center

48-8



48-9

CITY OF RIVERSIDE
PUBLIC UTILITIES



CITY OF RIVERSIDE
PUBLIC UTILITIES

Resource Expansion Plan

Major Drivers & Risk Considerations

- "Green Power" portfolio mandate (SB 1078) – 20% by 2015.
- Portfolio fuel diversification *(reduce reliance on coal)*.
- Geographic diversity of resource supply.
- Emergency resources *(i.e. Springs & other locations)*.
- Industry restructuring *(capacity reserve requirements a.k.a. ACAP)*.
- Expiration of existing power contracts.
  - CDWR 53 MW 2005, Deseret 52 MW 2010, BPA1 23 MW 2011
- Risk management & cost hedging strategies.
- City load growth (including annexations and conservation efforts).
- Obligation to serve load.

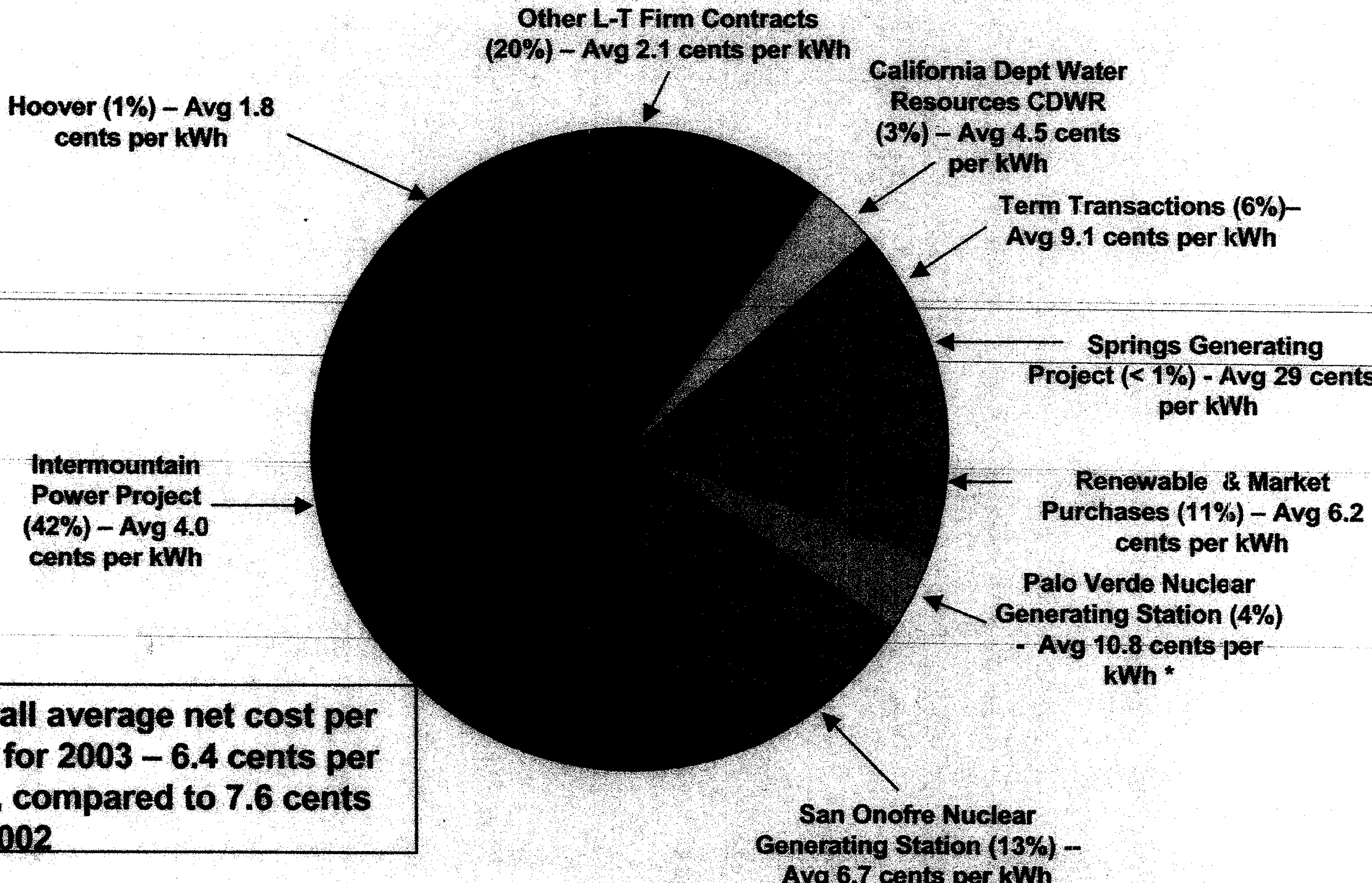
48-10

ELECTRIC UTILITY

RPU POWER RESOURCE MIX – JUNE 30, 2003

CITY OF RIVERSIDE
PUBLIC UTILITIES

48-11



Overall average net cost per kWh for 2003 – 6.4 cents per kWh, compared to 7.6 cents for 2002

* PVNGS debt will be paid off in 2004, reducing costs to 3.0 cents per kWh

One Plant or Two?

CITY OF RIVERSIDE
PUBLIC UTILITIES

		Dollar impact in millions
Cost Estimate to build one 50MW Power Plant in 2005	$	49.0
Cost Estimate for second plant in 2008		47.0
Total cost	$	96.0
Estimated cost to build two plants in 2005		75.0
Construction cost savings	$	21.0
Less:		
Additional operating costs		(0.9)
Additional interest expense on bonds		(7.9)
Net savings if build two in 2005 versus one	$	12.2
Other financial impacts:		
Use of cash reserves (current balance ~$45M)	$	(9.5)
Impact on days cash on hand (92 current)	20 days less	
Impact on debt service coverage ratio	4.6 down to 4.0	
Impact on Debt to Asset ratio	59.8 up to 62.4	
Possible impact on rates (possible implementation date in November 2005)		1.3%

48-12

Comparison of Risks
Peaking Needs

CITY OF RIVERSIDE PUBLIC UTILITIES

48-13

Internal Generation

- **Covers loss of resources during day (3 hour exposure)**
- No transmission risks
- Provides voltage support
- **Defers upgrades to VISTA substation**
- No direct counterparty risk (fuel still remains)
- Provides ACAP (Reserve) Coverage
- **Adds coverage for single largest contingency (227 MW)**
- No market price risk for excess energy
- Term not limited to 10 years

Standard Term Contract

- No additional debt on balance sheet
- No forced outage risk
- Avoid significant initial capital outlay
- No direct environmental concerns or air quality issues
- Flexibility as to term/price
- No fuel risk

Due to unknowns of future market prices and qualitative issues shown here, recommendation is to move forward with internal generation project

Next Steps

- Project approved by Board of Public Utilities – January 16, 2004
- Project approval request to Council Land Use Committee – January 22, 2004
- **Project approval request City Council – February 3, 2004**
- Bond Financing process (February – June)
- Future Project Approvals by Board and Council:
  - Award of contract for CTG (Combustion Turbine Generator)
  - Award of contract for EPC (Engineering, Procurement, & Construction)
  - Land Purchase at Wastewater Plant from Public Works
  - Miscellaneous equipment purchases
  - Periodic project updates
- California Energy Commission (CEC) approval – September 2004
- Groundbreaking – October 2004
- Projection Completion – May 2005

Recommendations

- Approve moving forward with RERC project and increase 2004 capital budget from $55 million to $75 million to include 2 units versus one
- Approve addition of 2 generation technicians to operate the new plant and participate in construction/inspection effective June 1, 2004 (to be hired summer 2004)

RESPONSE TO CURE DATA REQUESTS SET 1

REQUEST #3

RERC Project's Anticipated Operating Scenario

2002 Power Resources Expansion Plan

CITY OF RIVERSIDE

CITY COUNCIL MEMORANDUM

People Serving People

HONORABLE MAYOR AND CITY COUNCIL

DATE: December 17, 2002

ITEM NO: 57

SUBJECT: **2002 POWER RESOURCES EXPANSION PLAN**

BACKGROUND:

The Public Utilities' Power Resource Planning Group makes recommendations to the Director and the Board on a regular basis for long-range power acquisitions, market strategies and project feasibility. The foundation to the analysis behind these recommendations is the Power Resource Expansion Plan.

The Power Resource Expansion Plan is a 10-year system model that takes into account the City's forecasted load growth and existing generation portfolio, and then identifies future requirements in supply to meet demand in regards to timing (when?), size (how much?) and scope (on-peak? baseload?). The Expansion Plan is also a dynamic model that can help evaluate and address various forward strategies and "what-if" scenarios, such as market risk, fuel types and demand-side programs.

The Power Resource Expansion Plan was last presented to the Board in April 2001. Primary changes and improvements to the 2002 version of the plan include:

- Employment of new 2002 Long-Range Load Forecast numbers.
- Integration of Springs Generating Station into existing resource portfolio.
- Addition of renewable generation assets (green power) to future portfolio.
- Commitment to more diversified fuel mix.

The Board of Public Utilities received and filed this report on June 7, 2002.

This report was presented to the Land Use Committee at its meeting on August 15, 2002.

FISCAL IMPACT:

None

ALTERNATIVES:

None

COMMITTEE RECOMMENDATIONS:

Staff presented this item to the Land Use Committee on August 15, 2002. Three Committee members were present (No members were absent). Land Use Committee concurred in the suggested recommendations and move this item to the full City Council.

RECOMMENDATION:

That the City Council receive and file the attached report.

Prepared by:

Thomas P. Evans
Public Utilities Director

Approved by:

George A. Caravalho
City Manager

Approved as to form:

Gregory P. Priamos
City Attorney

Concurs with:

Paul C. Sundeen
Finance Director

Concurs with:

Chuck Beaty
Land Use Committee Chair

TPE/DS/LJC

Attachments: Board of Public Utilities minutes of June 7, 2002
2002 Power Resources Expansion Plan

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WATER ITEMS

CONSTRUCTION OF THE ARROYO DRIVE WATER MAIN REPLACEMENT PROJECT – AWARD OF BID NO. 5942

1) Approved the estimated capital expenditure of $693,000 for Work Order 703872, which includes all design, construction, contract administration, inspection, and change order contingencies for the Arroyo Drive Water Main Replacement Project; and

2) Approved and recommended that the City Council award a contract for construction of the Arroyo Drive Water Main Replacement Project, Bid No. 5942, to the lowest responsive bidder as determined by the City Council.

CONSTRUCTION OF PALMYRITA (RIVERSIDE SOUTH) WATER TREATMENT FACILITY – AWARD OF BID NO. 5903

1) Approved the estimated capital expenditure of $4.2 million dollars for Work Order 703928, which includes all design, construction, contract administration, inspection, and change order contingencies for construction of Palmyrita (Riverside South) Water Treatment Facility; and

2) Approved and recommended that the City Council award a contract for construction of Palmyrita (Riverside South) Water Treatment Facility, Bid No. 5903, to the lowest responsive bidder as determined by the City Council.

OTHER ITEMS

➡ ANNUAL PURCHASE ORDER REQUIREMENTS FOR FISCAL YEAR 2002-03

Approved the annual purchase order requirements for fiscal year 2002-03 in the estimated amount of $2,007,131.

DISCUSSION CALENDAR

2002 POWER RESOURCE EXPANSION PLAN

After Power Trading/Marketing Manager Steve Johnson gave a detailed presentation and answered questions from the Board members, the Board of Public Utilities received and filed this report.

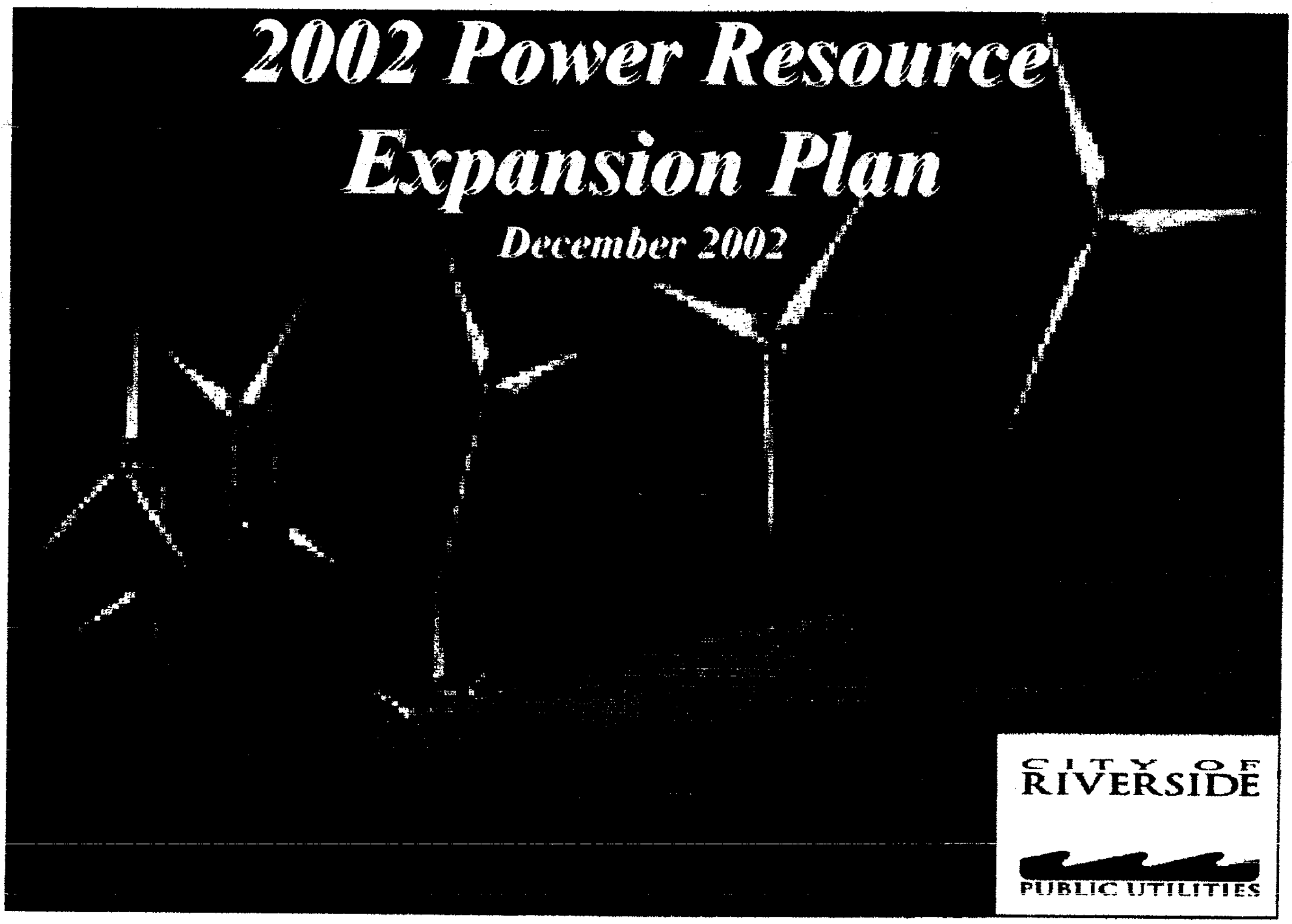
FIRST EXTENSION TO AGREEMENT FOR POLE INSPECTION, TESTING, TREATMENT, AND REINFORCEMENT

Following a brief overview by Assistant Director Steve Badgett, the Board of Public Utilities approved and recommended that the City Council:

1) Approve the First Extension to Agreement for Pole Inspection, Testing, Treatment, and Reinforcement between the City of Riverside and Osmose, Inc.; and

2) Authorize the City Manager, or his designee, to execute the necessary documents.

57


2002 Power Resource
Expansion Plan
December 2002
CITY OF
RIVERSIDE
PUBLIC UTILITIES

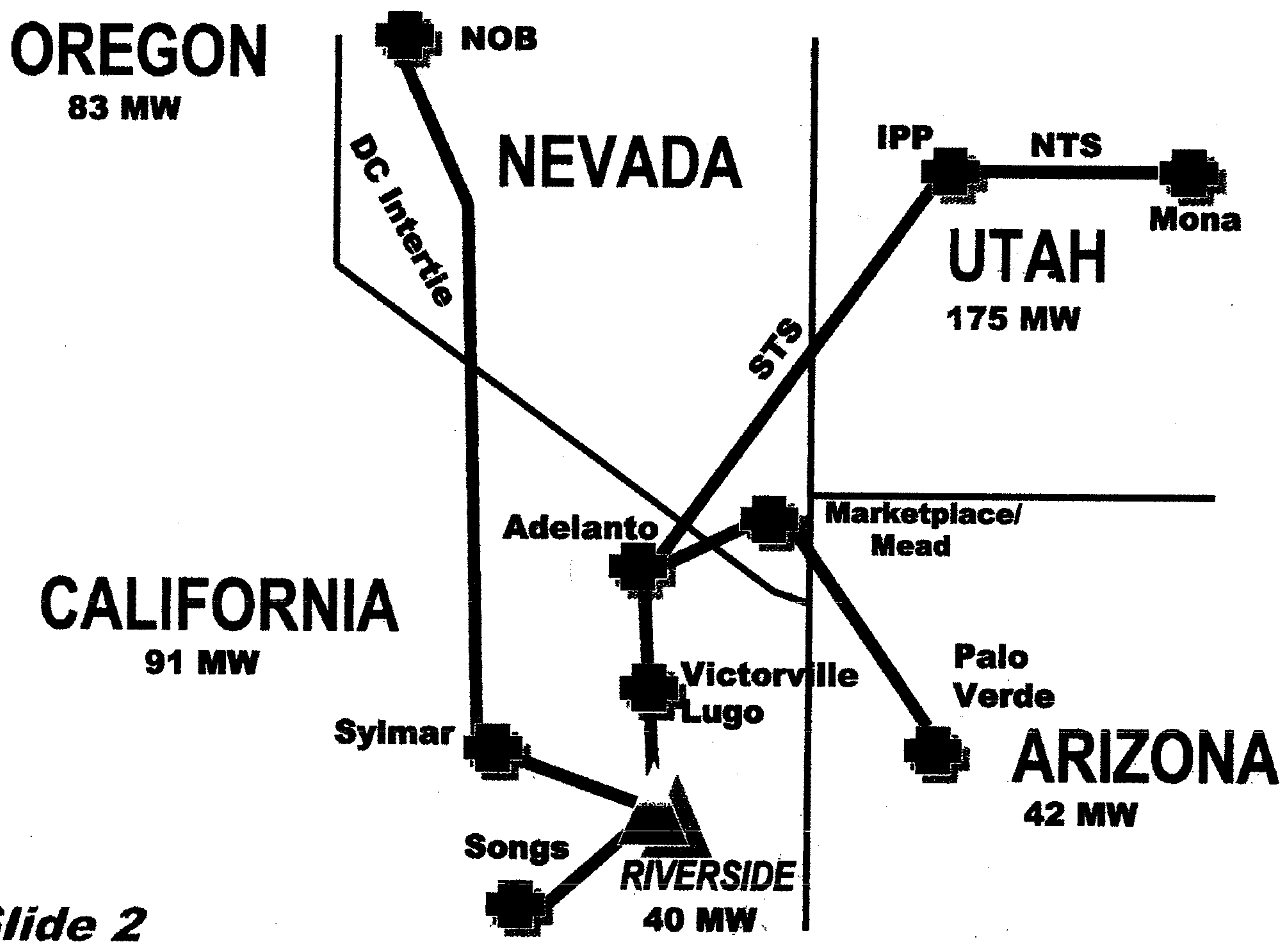
Resource Expansion Plan

Major Drivers & Risk Considerations

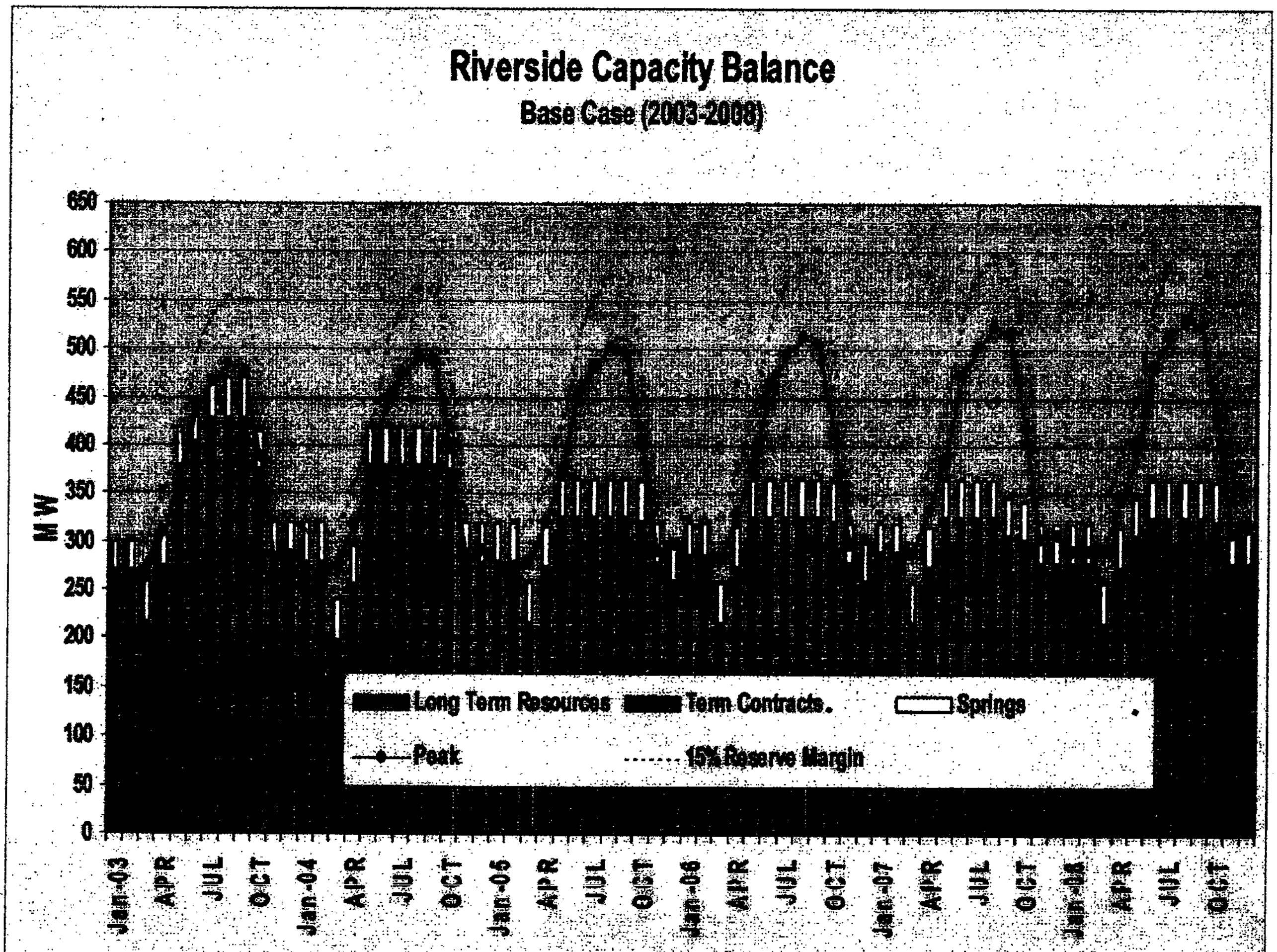
- "Green Power" portfolio mandate (SB 1078).
- Portfolio fuel diversification *(reduce reliance on coal).*
- Geographic diversity of resource supply.
- Emergency resources *(i.e. Springs & other locations).*
- Industry restructuring *(capacity reserve requirements).*
- Expiration of existing power contracts.
  - CDWR 53 MW 2005, Deseret 52 MW 2010, BPA1 23 MW 2011
- Risk management & cost hedging strategies.
- City load growth (including annexations and conservation efforts).
- Obligation to serve load.

Slide 1

RPU's Transmission Paths



Slide 2



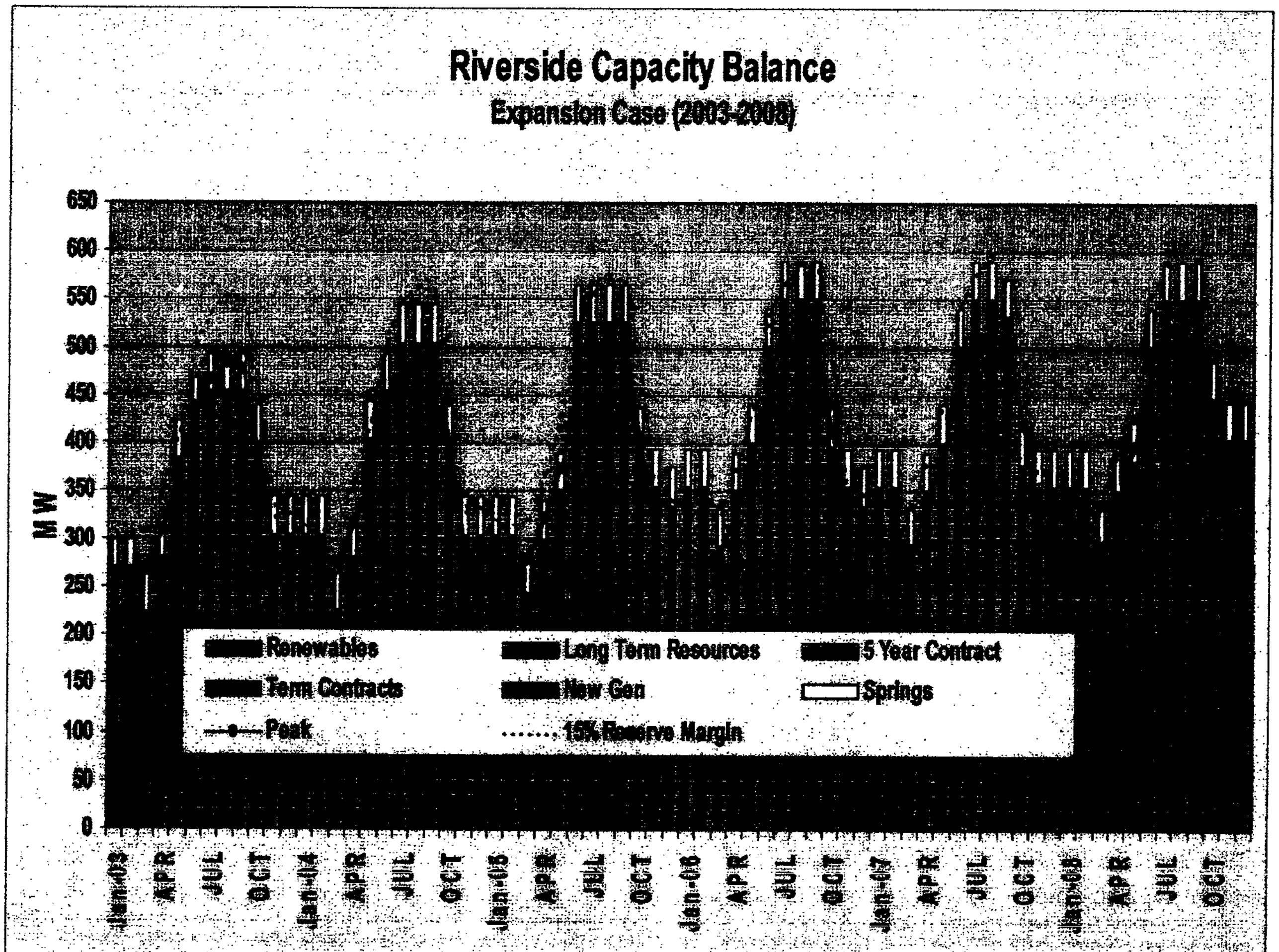
Riverside Capacity Balance
Base Case (2003-2008)
MW
650
600
550
500
450
400
350
300
250
200
150
100
50
0
Long Term Resources
Term Contracts
Springs
Peak
15% Reserve Margin
Jan-03
APR
JUL
OCT
Jan-04
APR
JUL
OCT
Jan-05
APR
JUL
OCT
Jan-06
APR
JUL
OCT
Jan-07
APR
JUL
OCT
Jan-08
APR
JUL
OCT

Slide 3

Resource Needs/Options Summary

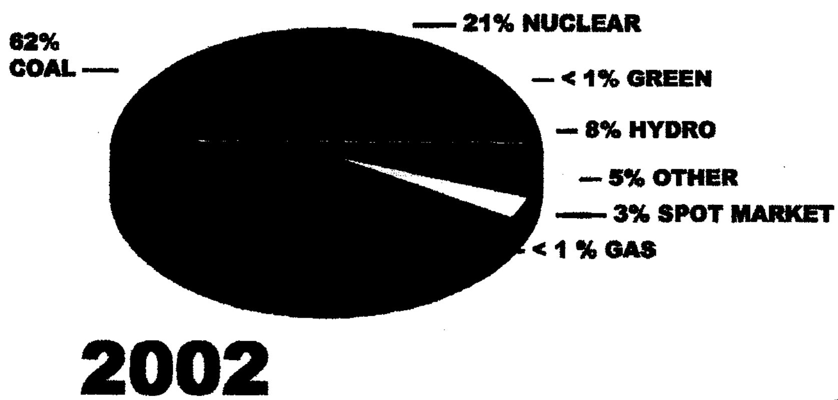
	Needs	Options	Comments
2003	25 MW Base Load 50 MW Summer Capacity	4 MW Wind, 5 MW Landfill Gas 20 MW Geothermal, 1 MW PV Term (1 Year) Contracts	To achieve goal of 10 percent "Green Power" in resource mix. Executed
2004	100 MW Summer Capacity	5 Year Capacity Contracts	To cover Monthly Peak and Reserve obligation.
2005	50 MW Peaking Resource 25 MW Summer Capacity	New Internal Generation Term (1 Year) Contract	Increase system emergency and reserve capability. To cover Monthly Peak and Reserve obligation.
2006/ 2007	50 MW Summer Capacity	Term (1 Year) Contract	To cover Monthly Peak and Reserve obligation.
2008	50 MW Peaking Resource	New internal generation	Increase system emergency and reserve capability.
2009/ 2010	100-125MW Summer Capacity 25 MW Gas Baseload	Replace Multi Year Capacity Contracts Combine Cycle / Contract	To cover Monthly Peak and Reserve obligation. Increase Natural Gas Share
	30 MW Baseload	Extend Deseret, IPP-3, Renewable, Natural Gas	Renewable Portfolio Standard, Fuel/Location diversity.

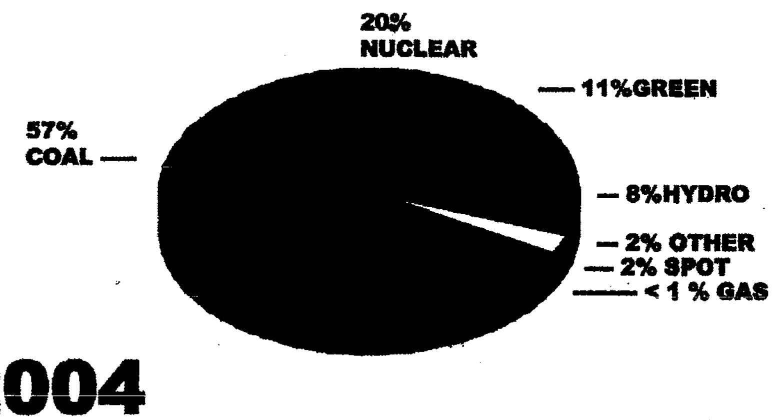
Slide 4


Riverside Capacity Balance
Expansion Case (2003-2008)
MW
650
600
550
500
450
400
350
300
250
200
150
100
50
0
Renewables
Long Term Resources
5 Year Contract
Term Contracts
New Gen
Springs
Peak
15% Reserve Margin
Jan-03
APR
JUL
OCT
Jan-04
APR
JUL
OCT
Jan-05
APR
JUL
OCT
Jan-06
APR
JUL
OCT
Jan-07
APR
JUL
OCT
Jan-08
APR
JUL
OCT

Slide 5

Resource Mix by Fuel Type

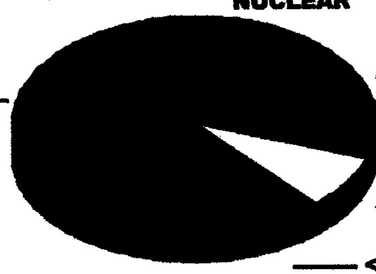




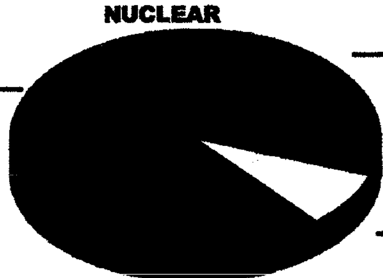
Slide 6

Resource Mix by Fuel Type 2010

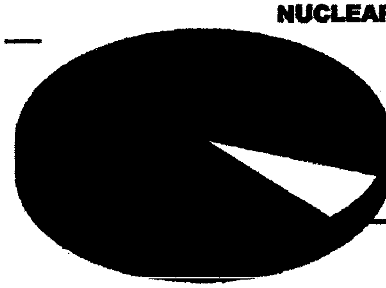
Coal Case



Green Case



Gas Case



Slide 7